NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE. OF THE AMERICAS, NEW YORK, NY 10018 (212) 840-1070 FAX (212) 302-2782

NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #17-5
December 7, 2017 8:00 a.m. – 5:00 p.m. EST
The Colonnade Hotel
Braemore/Kenmoree
120 Huntington Ave
Boston, MA
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 28840965**

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated August 1, 2017
NPCC Glossary of Terms, dated January 14, 2014

Introductions and Chair's Remarks

NPCC Antitrust Compliance Guidelines

Agenda Items:

1.0 Review of Agenda

2.0 RSC Meeting Minutes

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams
3.2 Executive Tracking Summary
3.3 NERC Project Tracking Spreadsheet

4.0 Open Action Items

4.1 Open Action Items List

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
5.2 RSC Scope of Work and Workplan
5.3 NPCC RSC Comment Submittal Deadline
5.4 Standards Efficiency Review
5.5 Implementation Guidance Development Presentation
5.6 Directory Manual – Periodic Review and Incorporate A-01
5.7 RISC 2017 Report
5.8 Project 2015-09 Establish and Communicate System Operating Limits
5.9 FERC CIP Audit Report

5.10 Resilience Presentation

6.0 NERC Reliability Standards

http://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer
Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	8/11/17 (F)	10/30/17 (F)	Scott Barfield-McGinnis
Project 2016-04 Modifications to PRC-025-1	12/13/17 (F)	12/13/17 (A)	Scott Barfield-McGinnis
Project 2015-10 Single Points of Failure TPL-001	10/23/17 (F)	10/23/17 (I)	Latrice Harkness
Revisions to the NERC Standard Processes Manual	5/3/17 (F)	5/3/17 (I)	Chris Larson
Project 2017-01 Modifications to BAL-003-1.1	12/1/17 (F)		Darrel Richardson
Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards	7/24/17 (I)		Darrel Richardson
Project 2017-06 Modifications to BAL-002-2	8/9/17 (I)		Darrel Richardson
Project 2015-09 Establish and Communicate System Operating Limits	11/13/17 (F)	11/13/17 (I)	Darrel Richardson
Project 2017-05 NUC-001-3 Periodic Review			Mat Bunch
Project 2016-02 Modifications to CIP Standards CIP-012-1	12/11/17 (F)	12/1117 (A)	Katherine Street Mat Bunch
2018-2020 Reliability Standards Development Plan	7/25/17 (F)		Soo Jin Kim
Project 2017-03 FAC-008-3 Periodic Review	12/13/17 (F)		Al McMeekin
2017 Periodic Review Standing Review Team - Standards Grading	8/2/17 (I)		Laura Anderson
Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards			Laura Anderson
Project 2017-07 Standards Alignment with Registration	8/30/17 (F)		Laura Anderson
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final			

6.2 Ballot History (Since last RSC Meeting)

6.3 Comment Form History (Since last RSC Meeting)

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies

7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)

7.2.1 None at this time

7.3 Solicitation for Informal Development Teams

7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

https://www.npcc.org/Standards/default.aspx

8.1 Current Activities:

8.1.1 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding status update

9.0 NPCC Non-Standards

https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

9.1 Directories:

9.1.1 Directory#7 *SPS* and NPCC Glossary term SPS

RAS Implementation/Transition

9.1.2 A-10 *Classification of BPS Elements* (status of TFCP review).

9.1.3 Directory#2 *Emergency Operations* and Directory#5 *Reserve* - (status of TFCO review).

9.1.4 Directory#4 System Protection Criteria – (status of Eversource Clarification Request)

9.1.5 Directory Manual --- Periodic Review and Incorporate A-01

10.0 RSC Member Items of Interest

10.1 RSC Roster

11.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

11.1 NERC Filings to FERC
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.2 FERC Orders / Rules
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.3 Federal Register
https://www.federalregister.gov/

11.4 FERC Sunshine Act Meeting Notice

11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

12.1 Standards Committee (SC)
http://www.nerc.com/comm/SC/Pages/default.aspx

January 18th - Call	March 15th - Meeting	April 19th - Call
June 14th - Meeting	July 19th - Call	September 7th Meeting
October 18th - Call	December 6th - Meeting	

SC 2018 Schedule:

January 17th – Call	February 14th – Call	March 14th – Meeting
April 18th – Call	May 16th – Call	June 13th – Meeting
July 18th – Call	August 22th – Call	September 13th Meeting
October 17th – Call	November 14th – Call	December 12th – Meeting

12.2 Standards Committee Process Subcommittee (SCPS)
http://www.nerc.com/comm/SC/Pages/Standards%20Committee%20Process%20Subcommittee%20SCPS/Standards-Committee-Process-Subcommittee-SCPS.aspx

January 4th - Call	February 21st - Call	March 14th – Meeting
March 29th – Call	May 22nd - Call	June 13th – Meeting
June 28th – Call	August 18th – Call	September 6th – Meeting
September 28th – Call	November 14th – Call	December 5th - Meeting

SCPS 2018 Schedule:

January 4th - Call	February 22nd - Call	March 13th – Meeting
March 29th – Call	May 24th - Call	June 12th – Meeting
June 28th – Call	August 23rd – Call	September 11th – Meeting
September 27th – Call	November 15th – Call	December 4th - Meeting

12.3 Standards Committee Project Management and Oversight Subcommittee (PMOS)
http://www.nerc.com/comm/SC/Pages/ProjectManagementandOversightSubcommittee(PMOS).aspx

January 26th - Call	March 15th - Meeting	April 27th - Call
June 14th - Meeting	July 27th - Call	September 7th Meeting
October 12th - Call	December 6th - Meeting	

PMOS 2018 Schedule:

March 14th - Meeting	June 13th - Meeting	September 12th Meeting
December 5th - Meeting		

12.4 Member Representatives Committee (MRC) Meeting
http://www.nerc.com/gov/bot/MRC/Pages/AgendaHighlightsandMinutes2013.aspx

12.5 Board of Trustees (BOT) Meeting
http://www.nerc.com/gov/bot/Pages/Agenda-Highlights-and-Minutes-.aspx

February 8-9 - Meeting	May 10-11 - Meeting	August 9-10 - Meeting
November 7-8 - Meeting		

BOT 2018 Schedule:

February 7-8 - Meeting	May 9-10 - Meeting	August 15-16 - Meeting
November 6-7 - Meeting		

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

13.0 NERC Items of Interest (Since last RSC Meeting)

13.1 Lessons Learned
http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx

13.1.1 There has been no new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

http://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx

There has been no new NERC Alerts released since the last RSC meeting.

13.3 Final NERC 2018 Business Plan and Budget

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 18th – Call	February 15th – Call	March 14-15th Meeting
April 12th – Call	May 23-25th Workshop	June 13-14th Meeting
July 12th – Call	August 16th – Call	September 19-20th Meeting
October 18th – Call	November 7-9th Workshop	December 7th Meeting

14.2 NPCC Board of Directors Meeting (BOD) 2017

February 1st - FRCC Office, Tampa, FL	March 22nd - Call	May 3rd – NPCC Office
June 1st – Call	June 28th – NPCC Office	August 2nd – Call
September 6th and 7th – Portland ME	November 1st – Call	December 6th – Boston MA

NPCC Board of Directors Meeting (BOD) 2018

January 31st – NERC Office, Washington, DC	March 21st - Call	May 2nd – NPCC Office
June 6th – Call	June 27th – NPCC Office	August 8th – Call
September 5th and 6th – Saratoga Springs NY	October 31st – Call	December 5th – Toronto ON

14.3 NPCC Business Plan and Budget 2018

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2017 Meeting Dates

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto
October 11th-12th, Niagara is on the lake, Ontario Canada
December 7th, Boston MA

15.2 RSC 2017 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

January 20	February 3	February 17
March 24	April 7	April 21
May 5	May 19	June 16
June 30	July 14	July 28
August 11	September 8	September 22
September 29	October 27	November 10
November 24	December 22	

15.3 Tentative RSC 2018 Meeting Dates

February/March, NextEra/Dominion, Juno Beach/Innsbrook
June, Saratoga NY
August, Toronto
October, Lewiston NY
December, Toronto ON

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

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

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

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

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NPCC REGIONAL STANDARDS COMMITTEE

AGENDA FOR MEETING #17-4
October 11, 2017 10:00 a.m. – 5:00 p.m. EST
October 12, 2017 8:00 a.m. – 12:00 p.m. EST
Sir Adam Beck Generating Station
14000 Niagara Parkway, Niagara-on-the-Lake
Ontario, Canada
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 28840965**

For Reference:
Glossary of Terms Used in NERC Reliability Standards, dated August 1, 2017
NPCC Glossary of Terms, dated January 14, 2014

	Name	Organization	Sector (s)	Day(s)	Comment
1.	Guy Zito	Northeast Power Coordinating Council		1 & 2	
2.	Gerry Dunbar	Northeast Power Coordinating Council		1 & 2	2nd Day Via Phone
3.	Ruida Shu	Northeast Power Coordinating Council		1 & 2	
4.	Mike Jones	National Grid	3	1 & 2	
5.	Quintin Lee	Eversource Energy	1	1 & 2	Via Phone
6.	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	Via Phone
7	Joel Charlebois	AESI, Inc.	Guest	1 & 2	
8.	Ron Falsetti	AESI, Inc.	Guest	1 & 2	
9.	Dan Grinkevich	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1 & 2	Via Phone
10.	David Ramkalawan	Ontario Power Generation, Inc.	4	1 & 2	
11.	David Kwan	Ontario Power Generation, Inc.	4	1 & 2	
12.	Constantin Chitescu	Ontario Power Generation, Inc.	4	1 & 2	
13.	Chantal Mazza	Hydro-Québec TransÉnergie	2	1 & 2	
14.	Laura Mcleod	New Brunswick Power Corporation	1	1 & 2	

15.	Payam Farahbakhsh	Hydro One Networks	1	1 & 2	
16.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1 & 2	
17.	Salvatore Spagnolo	NYPA	4	1 & 2	
18.	Brian Robinson	Utility Services, Inc.	5	1 & 2	
19.	Sean Bodkin	Dominion Resources Services	4	1 & 2	Via Phone
20.	Helen Lainis	IESO	2	1 & 2	Via Phone
21.	Kurtis Chong	IESO	2	1 & 2	2nd Day Via Phone
22.	Scott Berry	IESO	2	1	
23.	Michele Tondalo	The United Illuminating Company	1	1 & 2	
24.	Jim Grant	NYISO	2	1 & 2	
25.	Glen Smith	Entergy Services, Inc	4	1 & 2	
26.	Josh Eason	ISO-NE	2	1 & 2	
27.	David Kiguel	Independent	Guest	1 & 2	
28.	Sean Cavote	PSEG	4	1	
29.	Jerry Ancona	New York State Department of Public Service	6	1	Via Phone
30.	Vijay Puran	New York State Department of Public Service	6	1	Via Phone
31.	Mike Schiavone	National Grid	1	1	Via Phone
32.	John Pearson	ISO-NE	Guest	1	Via Phone
33.	Scott Barfield-McGinnis	NERC	Guest	1	Via Phone
34.	Latrice Harkness	NERC	Guest	1	Via Phone
35.	Darrel Richardson	NERC	Guest	1	Via Phone
36.	Mat Bunch	NERC	Guest	1	Via Phone
37.	Katherine Street	NERC	Guest	1	Via Phone
38.	Al McMeekin	NERC	Guest	1	Via Phone
39.	Laura Anderson	NERC	Guest	1	Via Phone

Introductions and Chair's Remarks
David Kwan welcomed everyone to OPG and provided a brief safety session on the facility.

NPCC Antitrust Compliance Guidelines
The NPCC Antitrust Compliance Guidelines were read by Ruida Shu.

Agenda Items:

1.0 Review of Agenda

Guy Zito welcomed Sean Cavote from PSEG to the RSC.
Sean Cavote introduced himself to the group.
Item 5.10 is added to the meeting agenda

2.0 RSC Meeting Minutes

Approval of Minutes—no additional revisions were made to the draft RSC meeting minutes of 6-7-17.
Mike Jones made a motion for approval.
Brian Robinson seconded the motion.
The meeting minutes were approved as read.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams
The RSC members reviewed the roster and found no changes necessary.

3.2 Executive Tracking Summary
Gerry Dunbar provided a brief update on the Executive Tracking Summary.

3.3 NERC Project Tracking Spreadsheet
Herb Schrayshuen suggested to be more selective on the NERC Projects. RSC should consider only the currently ballot and comment Projects.
Sean Bodkin suggested to ask the chair of the drafting teams to call-in since they are the SME and able to address any technical questions.

4.0 Open Action Items

4.1 Open Action Items List
Mike Jones suggested to put an agenda item for the December 2017 RSC meeting in regards to potential transfer A-01 document into the Directory Manual.

5.0 Items Requiring RSC Discussion

5.1 NERC Weekly Standards Bulletin
Guy Zito provided an update on the NERC Weekly Standards Bulletin.

5.2 NPCC 2017 Fall Compliance and Standard Workshop Topics
Mike Jones suggested to add Directory 8 updates into Gerry Dunbar's presentation.
Action Item: NPCC is asked to talk to Scott Nied to have him coordinate with Mark Hegerle to see if he is willing to talk about mechanism of the FERC audit and how it is different from a NERC audit.
Mike Jones provided some process insights on the FERC CIP Version 5 audit of~~on~~ New England Power Company (National Grid).

~~FERC uses data requests prior to the audit and they use the same audit schedule as NERC. FERC will provide potential recommendations at the end of the audit instead of a potential violation.~~

5.3 Compliance Guidance Presentation

Guy Zito provided a presentation on Compliance Guidance.

5.4 FERC Rulings on RAS

Guy Zito provided an update on NERC Standard PRC-012-2 Remedial Action Schemes (RAS). Guy Zito noted that in Order 837 issued on September 20, 2017 FERC approved PRC-012-2. Guy Zito explained that PRC-012-2 is subject to an Implementation Plan and the enforcement date of the Standard is January 1, 2021. Significantly, Guy Zito noted that the concept of a Limited Impact RAS within the Standard was approved and that NPCC Type III SPS's which have been though the regional review process will be recognized as Limited Impact RAS. Guy Zito provided an overview of the PRC-012-2 requirements.

Guy Zito provided background on the NPCC strategy to transition from SPS's to RAS. The RCC approved SPS list has been organized to indicate which SPS's do not conform to the RAS definition and which newly identified RAS's which were not SPS's have been added to the list.

Guy Zito described future actions including the revision of the NPCC Glossary term for SPS, approval process for newly identified RAS's and conforming changes to other NPCC documents.

5.5 RSC Scope of Work and Workplan

The plan is to have a small group (RSC Leadership) to update the Scope of Work and Workplan by the end of October 31, 2017.

Ruida Shu will send out the initial draft Scope of Work and Workplan to RSC on November 1, 2017.

Comments are due on November 15, 2017 back to Ruida Shu to compile all the comments for RSC to review on December 7, 2017 RSC meeting.

Action Item: The goal is to finalize the Scope of Work 2018 and Workplan 2018 by the end of December 2017 so it can be sent to NPCC BOD for approval in January 31, 2018.

5.6 Reliability Issues Steering Committee (RISC)

Guy Zito provided a presentation on Reliability Issues Steering Committee (RISC).

5.7 DOE OE-417

Sean Bodkin from Dominion presented the DOE OE-417 to the RSC members. There is a potential possibility for Dominion to submit an Implementation Guidance to the Compliance Committee.

5.8 Staff Report to the Secretary on Electricity Markets and Reliability and DOE Proposed NOPR

Guy Zito provided a presentation on DOE proposed NOPR.

5.9 Project 2016-02 CIP-012-1 Presentation

Ruida Shu provided a CIP-012-1 presentation to the RSC.

NPCC region had two concerns on CIP-012-1 and the SDT addressed both.

1. There is no clear demarcation to the communication path between Control Centers and the SDT made modifications to the standard language to address the demarcation issue.

2. There isn't enough time for the implementation period. The SDT increased the implementation period from 12 months to 24 months.

5.10 FERC 2017 CIP Audit Report

Guy Zito and Herb Schrayshuen provided detail information on the FERC 2017 Staff Report – Lessons Learned from Commission-Led CIP Version 5 Reliability Audits. ~~CIP Audit Report.~~ Mike Jones provided some additional process insights on the FERC CIP audit of New England Power Company (National Grid). ~~Mike Jones also gave some detail examples on the audit of National Grid.~~

6.0 NERC Reliability Standards

http://www.nerc.com/pa/Stand/Pages/Standards-Under-Development.aspx

6.1 Currently Posted Projects

Project	Comment Period End Date	Ballot Period End Date	Standards Developer	10/11/17 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	8/11/17 (F)	8/11/17 (I)	Scott Barfield-McGinnis	1:00PM
Project 2016-04 Modifications to PRC-025-1	9/7/17 (F)	9/8/17 (I)	Scott Barfield-McGinnis	1:15PM
Project 2015-10 Single Points of Failure TPL-001	10/23/17 (F)	10/23/17 (I)	Latrice Harkness	1:30PM
Revisions to the NERC Standard Processes Manual	5/3/17 (F)	5/3/17 (I)	Chris Larson	1:45PM
Project 2017-01 Modifications to BAL-003-1.1	8/9/17 (F)		Darrel Richardson	2:00PM
Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards	7/24/17 (I)		Darrel Richardson	2:15PM
Project 2017-06 Modifications to BAL-002-2	8/9/17 (I)		Darrel Richardson	2:30PM
Project 2015-09 Establish and Communicate System Operating Limits	11/13/17 (F)	11/13/17 (I)	Darrel Richardson	2:45PM
Project 2017-05 NUC-001-3 Periodic Review			Mat Bunch	3:00PM
Project 2016-02 Modifications to CIP Standards CIP-002-6	10/30/17 (F)	10/3017 (I)	Katherine Street Mat Bunch	3:15PM
2018-2020 Reliability Standards Development Plan	7/25/17 (F)		Soo Jin Kim	3:30PM
Project 2017-03 FAC-008-3 Periodic Review			Al McMeekin	3:45PM
2017 Periodic Review Standing Review Team - Standards Grading	8/2/17 (I)		Laura Anderson	4:00PM
Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards			Laura Anderson	4:15PM
Project 2017-07 Standards Alignment with Registration	8/30/17 (F)		Laura Anderson	4:30PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2:
Scott Barfield called in at 1:00PM to discuss the GMD standard.

The standard passed at 72.67% and it will be posted for a final ballot.
The comments received were non-substantial, the standard drafting team will not make significant changes to the standard itself.
There is~~are~~ some confusions on the white paper and the team will provide some clarifications.
The posting material is under review by the Standard Committee. SC will approve the final posting during ~~t~~the October 2017 SC conference call.
The final ballot is currently scheduled for Friday October 20, 2017.

Project 2016-04 Modifications to PRC-025-1:
Scott Barfield discussed Project 2016-04 with the RSC members.
The standard passed at 79.99%.
The Generator Forum raised several issues.
The SDT wrote the Implementation Plan based on the version 1 of the standard.
The SDT increased the Implementation Period by one year.
Expected next posting date: around October 23, 207.
The SDT decided that the increase of Implementation Period is not a substantial change.

Project 2015-10 Single Points of Failure TPL-001:
Latrice Harkness from NERC called in at 1:33PM.
The project goal is to address FERC Order 754 and 786.
The next SDT team meeting will be during the week of November 20, 2017.
The intention of the drafting team is for the entities to review assessments but take no action.

Revisions to the NERC Standard Processes Manual:
Guy Zito provided a brief update on the revisions to the NERC Standard Processes Manual in place of Chris Larson.
Section 5, 7 and 11 are the main changes to the NERC Standard Processes Manual.

Project 2017-01 Modifications to BAL-003-1.1
Darrel Richardson called in at 2:00PM to discuss Project 2017-01, Project 2017-02, Project 2017-06 and Project 015-09.
There are two SARs submitted for this Project 2017-01.
The SAR addressed the restructure of BAL-003-1.1
The SAR is reviewed by the Operating Committee and it was push to the SC to post the SAR for industry comments.
The SAR drafting team is looking to have their first meeting sometime in November or~~and~~ December 2017.

Project 2017-02 Modifications to Personnel Performance, Training, and Qualifications Standards:
The SAR was posted for comments, the SAR drafting team met two weeks ago to develop responses to comments.
The comments were mainly supporting the SAR.
The drafting team decided to not make any modifications to the SAR.
The SAR is on the December 2017 SC agenda for approval.
The retirement of PER-004 and adding a footnote.

Project 2017-06 Modifications to BAL-002-2:
The SAR has been posted and comments were collected.
The SAR drafting team is waiting for October 2017 SC conference call for appointment.
This project is only looking at two directives, notifying the RC if you can't recover in time and have a plan on your action.
FERC have some concerns on the current exemptions on the standard.

Project 2015-09 Establish and Communicate System Operating Limits
Main objectives for Project 2015-09 is to retire FAC-010, make modifications to FAC-011 and FAC-014, draft a new standard FAC-015.
There is a 30-day informal comment period that ends on October 30, 2017 in regards to the SOL exceedance and SOL definitions.
FAC-010 is recommended for retirement.
FAC-011 is modified the methodology for establishing SOL with its RC an TOP Area.
FAC-014 is modified and it is applicable to RC and TOP.
FAC-015 is a new standard for PC and TP to bridge the gap in operations and planning horizon.
There is a rationale document for the retirement of FAC-010 and the creation of FAC-015.

Project 2017-05 NUC-001-3 Periodic Review:
Mat Bunch called in at 3:18PM to discuss Project 2017-05.
The drafting team concluded that no requirements are in the red zone, there are a few requirements in the yellow zone and majority of them are in the green zone.
There is a WebEx on October 17, 2017.
Majority of the drafting team members agreed on table these requirements for future review.
Transmission Entity is a locally defined term with in the requirement but the drafting team is considering revising the term to Responsible Entity instead.

Project 2016-02 Modifications to CIP Standards CIP-002-6:
Mat Bunch and Katherine Street gave a presentation on Project 2016-02 Modifications to CIP standard.

2018-2020 Reliability Standards Development Plan:
Soo Jin Kim was unable to call in and update the RSC on 2018-2020 Reliability Standards Development Plan.

Project 2017-03 FAC-008-3 Periodic Review:
Al McMeekin called in at 3:53PM.
The kick off meeting was in August 2017 and last meeting was on the last week of September 2017.
The drafting team review the standard and found no major issues to the standard and will make a recommendation to leave the standard as is.

2017 Periodic Review Standing Review Team - Standards Grading:
Laura Anderson called in at 4:02PM to discuss Standards Grading, Project 2017-04 and Project 2017-07.

Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards:
The team has conducted two meetings and the third meeting will have a WebEx next week for one day.
The team believed that INT-004 and INT-010 can potentially be retired.
This will go out for a 45-day comment period.
INT-006 there is a potential to retire requirement 4 and 10.
Some minor modifications are recommended for INT-006 and the goal is to post this for industry comments.
INT-009 has the potential to retire a few requirements as well.

Project 2017-07 Standards Alignment with Registration:
The SAR drafting team recommendation has been submitted to SC for approval during their October 2017 conference call.
The goal is to alignment with registration.

6.2 Ballot History (Since last RSC Meeting)
Ruida Shu reviewed the Ballot History document in the meeting.

6.3 Comment Form History (Since last RSC Meeting)
Ruida Shu reviewed the Comment Form History document in the meeting.

7.0 NERC Drafting Team Nominations

7.1 Currently Posted Drafting Team Vacancies
7.1.1 None at this time

7.2 Closed Drafting Team Nominations (Since last RSC Meeting)
7.2.1 None at this time

7.3 Solicitation for Informal Development Teams
7.3.1 None at this time

8.0 NPCC Regional Reliability Standards

https://www.npcc.org/Standards/default.aspx

8.1 Current Activities:

8.1.1 PRC-006-NPCC-2 Automatic Underfrequency Load Shedding status update

Ruida Shu provided a status update on the PRC-006-NPCC-~~0~~2.

The Standard is current under a 45-day comment period which ends on October 16, 2017.

The drafting team did not create any new requirements in the standard and only clarified the language in the standard.

8.1.2 PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance status update

Ruida Shu indicated that the standard is filed to FERC for information only and it is also sent to the Regie.

9.0 NPCC Non-Standards

https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

Gerry Dunbar provided an update on Section 9.0:

9.1 Directories:

9.1.1 Directory#8 *System Restoration*.

TFCO and CO-1 have revised the document to eliminate duplicity with NERC Standards and revised three key restoration Glossary terms. NPCC Full Members approved these revisions on October 6, 2017.

9.1.2 Directory#7 *SPS* and NPCC Glossary term SPS

RAS Implementation/Transition

See Section 5.4.

9.1.3 A-10 *Classification of BPS Elements* (status of TFCP review).

The CP-11 Working Group is currently reviewing the existing methodology and considering alternative proposals to identify critical facilities within NPCC. CP-11 anticipates delivering its final report to the TFCP on November 7 and 8 and will request TFCP agreement to present the report to the RCC for endorsement in December. Subsequent to RCC endorsement, the CP-11 proposals will be tested in Phase 2 of the A-10 review during 2018.

9.1.4 Directory#2 *Emergency Operations* and Directory#5 *Reserve* - (status of TFCO review).

TFCO Working Groups currently reviewing both Directories for consistency with NERC standards. TFCO anticipates posting Directory#2 to the Open Process during the 4th Qtr. of 2017; anticipate posting D#5 in mid-2018.

9.1.5 Directory#4 System Protection Criteria – (status of Eversource Clarification Request)

TFSP rendered a Clarification on behalf of Eversource on trip coil monitoring. Clarification was posted to the Open Process and TFSP anticipates presenting the Clarification to the RCC for approval in December 2017.

10.0 RSC Member Items of Interest

10.1 RSC Roster

The members of RSC reviewed the roster and will add David Kwan back onto the OPG roster as an additional alternate member.

11.0 Standards Activity Post NERC BOT Approval

(Since last RSC Meeting)

11.1 NERC Filings to FERC
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.2 FERC Orders / Rules
http://www.nerc.com/FilingsOrders/Pages/default.aspx

11.3 Federal Register
https://www.federalregister.gov/

11.4 FERC Sunshine Act Meeting Notice

11.5 FERC Open Meeting Summaries

12.0 NERC Meetings

12.1 Standards Committee (SC)
http://www.nerc.com/comm/SC/Pages/default.aspx

January 18th - Call	March 15th - Meeting	April 19th - Call
June 14th - Meeting	July 19th - Call	September 7th Meeting
October 18th - Call	December 6th - Meeting	

SC 2018 Schedule:

January 17th – Call	February 14th – Call	March 14th – Meeting
April 18th – Call	May 16th – Call	June 13th – Meeting
July 18th – Call	August 22th – Call	September 13th Meeting
October 17th – Call	November 14th – Call	December 12th – Meeting

12.2 Standards Committee Process Subcommittee (SCPS)
http://www.nerc.com/comm/SC/Pages/Standards%20Committee%20Process%20Subcommittee%20SCPS/Standards-Committee-Process-Subcommittee-SCPS.aspx

January 4th - Call	February 21st - Call	March 14th – Meeting
March 29th – Call	May 22nd - Call	June 13th – Meeting
June 28th – Call	August 18th – Call	September 6th – Meeting
September 28th – Call	November 14th – Call	December 5th - Meeting

SCPS 2018 Schedule:

January 4th - Call	February 22nd - Call	March 13th – Meeting
March 29th – Call	May 24th - Call	June 12th – Meeting
June 28th – Call	August 23rd – Call	September 11th – Meeting
September 27th – Call	November 15th – Call	December 4th - Meeting

12.3 Standards Committee Project Management and Oversight Subcommittee (PMOS)
http://www.nerc.com/comm/SC/Pages/ProjectManagementandOversightSubcommittee(PMOS).aspx

January 26th - Call	March 15th - Meeting	April 27th - Call
June 14th - Meeting	July 27th - Call	September 7th Meeting
October 12th - Call	December 6th - Meeting	

PMOS 2018 Schedule:

March 14th - Meeting	June 13th - Meeting	September 12th Meeting
December 5th - Meeting		

12.4 Member Representatives Committee (MRC) Meeting
http://www.nerc.com/gov/bot/MRC/Pages/AgendaHighlightsandMinutes2013.aspx

12.5 Board of Trustees (BOT) Meeting
http://www.nerc.com/gov/bot/Pages/Agenda-Highlights-and-Minutes-.aspx

February 8-9 - Meeting	May 10-11 - Meeting	August 9-10 - Meeting
November 7-8 - Meeting		

BOT 2018 Schedule:

February 7-8 - Meeting	May 9-10 - Meeting	August 15-16 - Meeting
November 6-7 - Meeting		

12.6 Reliability Issues Steering Committee (RISC)
http://www.nerc.com/comm/RISC/Related%20Files%20DL/ERO_Reliability_Risk_Priorities_RISC_Reccommendations_Board_Approved_Nov_2016.pdf

13.0 NERC Items of Interest (Since last RSC Meeting)

13.1 Lessons Learned
http://www.nerc.com/pa/rrm/ea/Pages/Lessons-Learned.aspx

13.1.1 There have been one new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

http://www.nerc.com/pa/rrm/bpsa/Pages/Alerts.aspx

There has been one new NERC Alerts released since the last RSC meeting.

13.3 Final NERC 2018 Business Plan and Budget

14.0 Other Items of Interest

14.1 NPCC Compliance Committee (CC) Schedule

January 18th – Call	February 15th – Call	March 14-15th Meeting
April 12th – Call	May 23-25th Workshop	June 13-14th Meeting
July 12th – Call	August 16th – Call	September 19-20th Meeting
October 18th – Call	November 7-9th Workshop	December 7th Meeting

14.2 NPCC Board of Directors Meeting (BOD) 2017

February 1st - FRCC Office, Tampa, FL	March 22nd - Call	May 3rd – NPCC Office
June 1st – Call	June 28th – NPCC Office	August 2nd – Call
September 6th and 7th – Portland ME	November 1st – Call	December 6th – Boston MA

NPCC Board of Directors Meeting (BOD) 2018

January 31st – NERC Office, Washington, DC	March 21st - Call	May 2nd – NPCC Office
June 6th – Call	June 27th – NPCC Office	August 8th – Call
September 5th and 6th – Saratoga Springs NY	October 31st – Call	December 5th – Toronto ON

14.3 NPCC Business Plan and Budget 2018

15.0 Future RSC Meetings and Conference Calls

15.1 RSC 2017 Meeting Dates

March 8th-9th, FRCC, Tampa FL
June 7th-8th, Saratoga NY
August 23rd-24th, Toronto
October 11th-12th, Niagara is on the lake, Ontario Canada
December 7th, Boston MA

15.2 RSC 2017 Conference Call Schedule (calls can be schedule as needed) all Calls are planned to start at 10:00 a.m. (call: 415-655-0003 (USA) / 416-915-6530 (Canada), Guest Code 28840965)

January 20	February 3	February 17
March 24	April 7	April 21
May 5	May 19	June 16
June 30	July 14	July 28
August 11	September 8	September 22
September 29	October 27	November 10
November 24	December 22	

15.3 Tentative RSC 2018 Meeting Dates

February/March, NextEra/Dominion, Juno Beach/Innsbrook Last week of February or 1st week of March 2018
June, Saratoga NY June 20-21, 2018
August, Toronto August 29-30, 2018
October, Lewiston NY October 10-11, 2018
December, Toronto ON

The meeting is adjourned at 11:30AM on October 12, 2017.

Respectfully Submitted,

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

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

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

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

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

NPCC Representatives on NERC Standards Drafting Teams

Project No.	Project Title	DT Type	NPCC Representatives	Company	Telephone	E-mail Address
2010-05.2	Remedial Action Schemes (Phase 3 of Protection Systems)	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2013-03	Geomagnetic Disturbance Mitigation	Standard	Per-Anders Lof Rui Sun Louis Gibson	National Grid Dominion Hydro Quebec	781-907-5581	per-anders.lof@nationalgrid.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-552-4022	brian.evans-mongeon@utilitysvcs.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-09	Establish and Communicate System Operating Limits - FAC-010, FAC-011, FAC-014	Standard	Dean Laforest Sam Jager	ISO-NE IESO		
2015-10	Single Points of Failure - TPL-001	Standard	Ovidiu Vasilachi Rich Kowalski	IESO Observer ISO-NE		
2016-01	Modifications to TOP and IRO Standards - TOP-001, IRO-002	Standard				
2016-02	Modification to CIP Standards	Standard	Steve Brain Philippe Labrosse	Dominion Resource Services, Inc. Hydro-Quebec TransEnergie		
2016-03	Cyber Security Supply Chain Management	Standard	Norm Dang David Bryan Gayle	IESO Dominion Resource Services, Inc.		
2016-04	Modifications to PRC-025-1	Standard	Juan Alvarez	Utility Services		
2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	Standard	Tim Kucey	PSEG Fossil, LLC		
2017-01	Modifications to BAL-003-1.1	Standard				
2017-02	Modifications to Personnel Performance, Training, and Qualifications Standards - PER-003, PER-004	Standard				
2017-06	Modifications to BAL-002-2	Standard				
2017-07	Standards Alignment with Registration	Standard				

Source = NERC Standard Drafting Team Rosters - September 2016

NPCC Document Open Process Executive Tracking Summary

Revised: **12/6/2017** Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/SitePages/NonStandardsList.aspx

Line No.	Type	Document	Description	Latest Revision	Comments	Status
1	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13		TFSP revisions approved at the RCC on 12/05/17.
2	Directory Clarification	Directory #4	System Protection Criteria	N/A		TFSP Clarification approved at the RCC on 12/05/17.
3	Regional Standard	PRC -006-NPCC-1	Automatic UFLS	Feb-12	Comment Period Concluded 10/16.	Drafting Team to Consider Open Process Comments…..pending 2nd Open Process Posting.
4	Directory	Directory#2	Emergency Operation	Jun-09	Comment Period Anticipated January 2018.	CO-8 Working Group to Request TFCO Permission to Post at TFCO December Mtg.

NPCC Directory Executive Tracking Summary

Revised: 12/6/2017 Further details regarding the individual documents may be found at:

	Document	Developed From	Title of Directory	Responsible Task Force	Latest Version	Comments	Status
1	Directory #1	Criteria A-2	Design and Operation of the Bulk Power System	TFCP	Oct-15		
2	Directory #2	Criteria A-3	Emergency Operations	TFCO	Jun-09	Comment Period Anticipated October 2017.	CO-8 Working Group to Request TFCO Permission to Post at TFCO December Mtg.
3	Directory #3	Criteria A-4	Maintenance Criteria for Bulk Power System Protection	TFSP	Jun-09	Directory#3 retired effective April 1st, 2015 coinciding with the enforcement date of PRC -005-2.	
4	Directory #4	Criteria A-5	Bulk Power System Protection Criteria	TFSP	Oct-15		
5	Directory #5	Criteria A-6	Reserve	TFCO	Oct-12		TFCO Working Group CO-1 reviewing reformatted draft of Directory#5.
6	Directory #6		Regional Reserve Sharing		Apr-12		
7	Directory #7	Criteria A-11	Special Protection Systems	TFSP	Jul-13		Pending approval of PRC-012-2 TFSP and TFSS to consider review of Directory#7 criteria and NPCC Glossary definition of SPS.
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10	Full Member Ballot to Conclude on October 6th, 2017.	TFCO revisions approved on October 6, 2017.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		NPCC Full Members approved retirement of D#9 and D#10 pending full enforcement of MOD-25-2. (July 2019).
10	Directory #10	Criteria A-14	Verification of Generator Gross and Net Reactive Power Capability	TFCO	Dec-11		See D#9.
11	Directory#11	Criteria A-15	Disturbance Monitoring	TFSP	Oct-16	D#11 Approved October 2016.	
12	Directory#12		UFLS	TFSS	Oct-12		

NPCC Directory Criteria Clarifications

Revised: 12/6/2017 Further details regarding the individual documents may be found at: https://www.npcc.org/Standards/Directory%20Interpretations/Forms/Public%20List.aspx

Line No.	Document	Title of Directory	Date Final	Task Force Review	Posted Open Process?	RCC Approval	Comments	Status
1	Directory #8 Interpretation	System Restoration	6/18/2012	TFCO	N/A	N/A	Interpretation on behalf of the NYSRC	Complete
2	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	8/28/2012	TFSP	N/A	N/A	Interpretation on behalf of Bangor Hydro	Complete
3	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	12/14/2012	TFSP	N/A	N/A	Interpretation on behalf of Con Ed	Complete
4	Directory #3 Interpretation	Maintenance Criteria for Bulk Power System Protection	2/15/2013	TFSP	N/A	N/A	Response Clarified - Interpretation on behalf of Acumen Engineered Solutions	Complete
5	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	10/25/2013	TFSP	N/A	N/A	Interpretation on behalf of Hydro One Networks	Complete
6	Directory#3 Interpretation	Maintenance Criteria for Bulk Power System Protection	3/4/2015	TFSP	Yes	Yes	Interpretation on behalf of IESO-MACD	Complete.
7	Directory#8 Clarification	System Restoration	12/1/2015	TFCO	Yes	Yes	Clarification on Behalf of OPG.	Complete.
8	Directory#5 Clarification	Reserve	9/7/2016	TFCO	Yes	Yes	Clarification on Behalf of the NYISO.	Complete

12/6/2017

Filing Period	Filing Due	Filing Submitted	Comments
October 1 to December 31, 2012	3/1/2013	3/1/2013	This filing is NPCC's initial quarterly filing covering the October 1 to December 31, 2012 period and covers the changes to the NPCC Criteria as a result of voting by the Full Members of NPCC.
January 1 to March 31, 2013	6/1/2013	N/A	No changes were made during the refeenced period which required filing.
April 1 to June 30, 2013	9/1/2013	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2013	12/1/2013	11/25/2013	Revisions to D#7 and D#12 approved by the Full Members on 7/9/2013.
October 1 to December 31, 2013	3/1/2014	N/A	No changes were made during the referenced period which required filing.
January 1 to March 31, 2014	6/1/2014	N/A	No changes were made during the referenced period which required filing.
April 1 to June 30, 2014	9/1/2014	N/A	No changes were made during the referenced period which required filing.
July 1 to September 30, 2014	12/1/2014	N/A	No changes were made during the referenced period which required filing.
October 1 to December 31, 2014	3/1/2015	2/23/2015	(1) 10/15/14 NPCC Full Members approved retirement of D#3 effective 4/01/15 coinciding with enforcement date of PRC -005-2.
	3/1/2015	N/A	(2) 10/6/14 the RSC approved revisions to the Directory Manual which incorporated cost considerations into the Manual.
January 1st to March 31st 2015	6/1/2015	N/A	No changes were made during the referenced period which required filing.
April 1st to June 30th 2015	9/1/2015	N/A	No changes were made during the referenced period which required filing.

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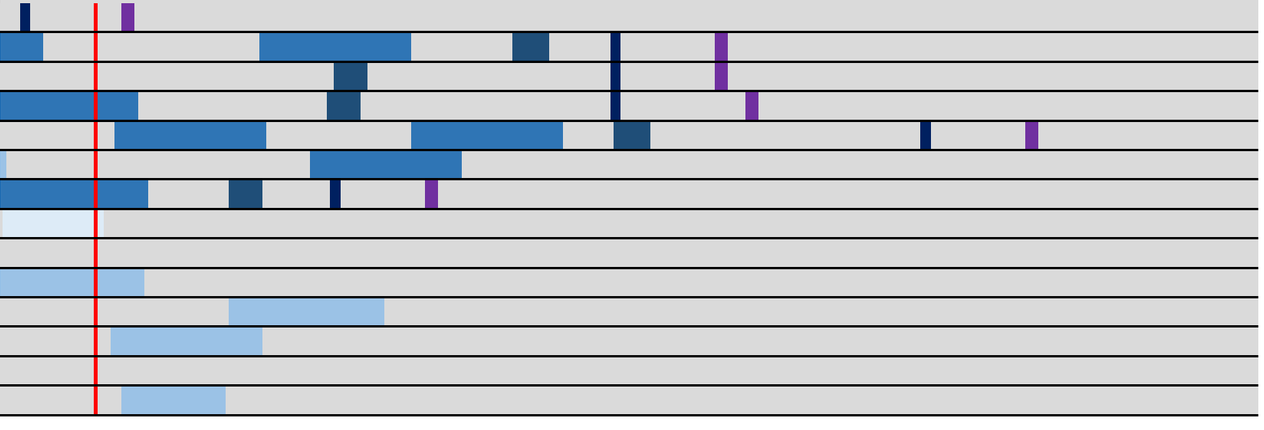
Nom-SAR/D QR | Posting-SAR or PR | Posting-Comment Only | Posting Comment & Ball | Final Ballot Present to BO | Filing / Post Approval Train

[HOME](#)

U	Project (Filter)	DO NOT SORT (Filtering Ok) Deliverables (Filter)	Early/(Late) Days (Filter)	Baseline/ Current (Filter)
G	2013-03 - Geomagnetic Disturbance Mitigation	TPL-007-2	123	Current
Ye	2015-09 - Establish and Communicate System O	FAC-010-3, FAC-011-3, and FA		Current
G	2015-10 - Single Points of Failure TPL-001	TPL-001-5	(31)	Current
Ye	2016-02 - Modifications to CIP Standards	Directives, Control Center Con	(112)	Current
Ye	2016-02 - Modifications to CIP Standards	Address TO Control Centers Pe	(197)	Current
Ye	2016-02 - Modifications to CIP Standards	Address all remaining V5TAG i		N/A
G	2016-04 - Modifications to PRC-025-1	PRC-025-2		Current
Ye	2017-01 - Modifications to BAL-003-1	BAL-003-2		Proposed
Ye	2017-02 - Modifications to Personnel Performan	PER-003-2, retire PER-004-2		Proposed
Ye	2017-03 - Periodic Review of FAC-008-3 Standar	Periodic Review Recommenda		N/A
Ye	2017-04 - Periodic Review of Interchange Sched	Periodic Review Recommenda		N/A
Ye	2017-05 - Project 2017-05 NUC-001-3 Periodic R	Periodic Review of NUC-001-3		N/A
R	2017-06 - Project 2017-06 Modifications to BAL-	BAL-002-3		Proposed
G	2017-07 - Stds Alignment with Registration			Proposed



Project Name	Status	Comments	Deliverable	Deadline	Priority in RSDP, click to see applicable	P81 Req (2013)	Number of Directives	No. of Guidances (see Note 2)	Directionally consistent with IERP findings (See Note 5)	Developer	PMOS Liaison	Affected Standards	Last Updated
(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	(Sorting okay)	HOME
Geomagnetic Disturbance Mitigation	Pending Regulatory Filing	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. The SAR was accepted by the Standards Committee on March 15, 2017. The standard passed final ballot and was adopted by the NERC Board at their November 2017 meeting.	TPL-007-2	5/29/2018	Footnote 8, High	N/A	4	N/A	N/A	Scott Barfield	Jennifer Sterling	TPL-007-1	11/29/2017
Establish and Communicate System Operating Limits	Responding to Comment	The team posted the definition of SOL and SOL Excedence for a 30-day informal comment period from September 29 - October 30, 2017. The standards FAC-010-3, 011-4, 014-3, and 015-1 were posted	FAC-010-3, FAC-011-3, and FAC-014-2	N/A	Footnote 7, Medium	N/A	N/A	N/A	N/A	Darrel Richardson & Al McMeekin	Ken Lanehome	FAC-010-3, FAC-011-3, and FAC-014-2	11/15/2017
Single Points of Failure TPL-001	Responding to Comment	The SC authorized the standard for posting on September 7, 2017. The standard is posted for a 45-day formal comment period and initial ballot from September 7-October 23, 2017. The team will be meeting at LG & E KU November 28-30, 2017 to respond to comments	TPL-001-5	N/A	Footnote 8, High	N/A	2 directives at P40 & P89 (Click this link for FERC Order)	N/A	N/A	Latrice Harkness	Mark Pratt	TPL-001-4	11/29/2017
Modifications to CIP Standards	Working to Comment Posting	The Virtualization concept comment form No. 2 was posted for a 30-day informal comment period. The team will begin drafting the applicable standards for comment and ballot in November 2017.	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome, Ash Mayfield, and Kirk Rosener	CIP Stds. - Unknown	11/15/2017
Modifications to CIP Standards	Posted	The team is considering comments from the initial ballot and will repost for comment in October 2017.	Directives, Control Center Comm Nets (CIP-012-1)	N/A	Footnote 8, High	N/A	2	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash		11/15/2017
Modifications to CIP Standards	Responding to Comment	The CIP-002-6 is posted for a 45-day formal comment period from September 14 - October 30. The revisions address issues from the Version 5 Transition Advisory Group (V5TAG) on the applicability of	Address TO Control Centers Performing Transmission	N/A	Footnote 8, High	N/A	N/A	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash	CIP-002-5.1a	11/15/2017

Project **2013-03** **Home**

Project Name	Geomagnetic Disturbance Mitigation
Status	Pending Regulatory Filing
Comments	FERC issued Order No. 830 on September 22, 2016 approving TPL-007-1 and directing modifications. The SDT will develop revised or new requirements to enhance the benchmark GMD event used in GMD assessments, require collection of GMD data, and establish deadlines for GMD Corrective Action Plans and mitigation measures. Revisions must be filed by May 29, 2018. The SAR was accepted by the Standards Committee on March 15, 2017. The standard passed final ballot and was adopted by the NERC Board at their November 2017 meeting.
Deliverable	TPL-007-2
Deadline	**Tuesday, May 29, 2018**
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	4
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Scott Barfield
PMOS Liaison	Jennifer Sterling
Affected Standards	TPL-007-1
Last Updated	11/29/2017

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	10/20/2016	11/9/2016	10/20/2016	11/9/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	12/16/2016	1/20/2017	12/20/2016	1/19/2017	4		
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	6/28/2017	8/11/2017	6/15/2017	7/30/2017	(13)		Passed
CAB - Com/Add Ballot 2			9/11/2017	10/26/2017			Changed from 9/11 to 9/22 to stagger 2013-03, 2015-09, and 2015-10.
CAB - Com/Add Ballot 3			***11/29/2017***	***1/13/2018***			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	10/20/2017	10/30/2017	2/20/2018	3/2/2018	123		Passed
PTB - Present to BOT	11/7/2017	11/9/2017	5/1/2018	5/3/2018	175		Adopted
Filing - Filing with Regulators	12/7/2017	12/10/2017	5/26/2018	**5/29/2018**	170		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
No dates provided	6/1/2016	Project finished prior to 2015.
Accept Baseline Schedule	6/14/2017	Accepted by unamious consent.
Schedule Adjustment	8/10/2017	Changed from 9/11 to 9/22 to stagger 2013-03, 2015-09, and 2015-10.

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Responding to Comment
Comments	The team posted the definition of SOL and SOL Excedence for a 30-day informal comment period from September 29 - October 30, 2017. The standards FAC-010-3, 011-4, 014-3, and 015-1 were posted for a 45-day formal comment period from September 29 - November 13, 2017. The team will be responding to comments.
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 7, Medium
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson & Al McMeekin
PMOS Liaison	Ken Lanehome
Affected Standards	FAC-010-3, FAC-011-3, and FAC-014-2
Last Updated	11/15/2017

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review			4/4/2016	4/14/2016		Not needed	
SP1 - SAR/PR/WP Posting 1	8/20/2015	9/21/2015	8/20/2015	9/21/2015			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	7/14/2016	8/12/2016	7/8/2016	8/7/2016	(6)		
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/29/2017	11/13/2017	9/22/2017	11/5/2017	(7)		Posting date changed see notes 8/10 and 8/25.
CAB - Com/Add Ballot 2	1/17/2018	3/2/2018	1/17/2018	3/2/2018			
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	4/2/2018	4/12/2018	4/2/2018	4/12/2018			
PTB - Present to BOT	5/1/2018	5/3/2018	5/1/2018	5/3/2018			
Filing - Filing with Regulators	6/1/2018	6/4/2018	6/1/2018	6/4/2018			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Explain delay	5/1/2016	The apparent delay in the project is due to missing an earlier update to the PMOS Annual Project Calendar. Baseline Schedule has not been adjusted.
Developer change	1/13/2017	Transition from Lacey Ourso to Darrel Richardson.
Developer change	4/1/2017	Added Al McMeekin to the project.

Project	**2015-10**
Project Name	Single Points of Failure TPL-001
Status	Responding to Comment
Comments	The SC authorized the standard for posting on September 7, 2017. The standard is posted for a 45-day formal comment period and initial ballot from September 7-October 23, 2017. The team will be meeting at LG & E KU November 28-30, 2017 to respond to comments.
Deliverable	TPL-001-5
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	2 directives at P40 & P89 (Click this link for FERC Order)
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Latrice Harkness
PMOS Liaison	Mark Pratt
Affected Standards	TPL-001-4
Last Updated	11/29/2017

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	11/12/2015	12/1/2015	1/18/2016	2/1/2016	67		
Nominations - DT	7/22/2016	8/5/2016	7/25/2016	8/8/2016	3		
QR - Quality Review			5/30/2016	6/9/2016			
SP1 - SAR/PR/WP Posting 1	11/12/2015	12/17/2015	11/12/2015	12/17/2015			
SP2 - SAR/PR/WP Posting 2	5/26/2016	6/24/2016	6/15/2016	7/15/2016	20	Expanded Scope	
CP1 - Comment Period 1	4/25/2017	5/24/2017	4/25/2017	5/24/2017		Other	Team added informal comment period
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/8/2017	10/23/2017	7/5/2017	8/18/2017	(65)		Held at 9/7 to stagger 2013-03 and 2015-09.
CAB - Com/Add Ballot 2	2/6/2018q	#VALUE!	10/18/2017	12/1/2017	#VALUE!		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/8/2018	2/17/2018	1/8/2018	1/17/2018	(31)		
PTB - Present to BOT	5/1/2018	5/3/2018	2/1/2018	2/3/2018	(89)		
Filing - Filing with Regulators	6/1/2018	6/4/2018	3/1/2018	3/4/2018	(92)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Expansion of Scope	6/14/2016	FERC directives added (P40 & P89) additional scoping in addition to industry comments following the second SAR posting. The MOD references are being updated due to some retiring
Developer change	1/13/2017	Transition from Lacey Ourso to Soo Jin Kim until a new developer is assigned.
Accept Schedule	4/27/2017	Accepted by PMOS.
Schedule deviation	6/13/2017	Baseline initial ballot of 7/5/2017 moved to 9/7/2017 due addressing comments and scope of SAR. Schedule accounts for SC not meeting in August.
Schedule Adjustment	8/10/2017	No adjustment required 2013-03, 2015-09, and 2016-02 were staggered to spread postings out.

Project **2016-02** **Home**

Project Name	Modifications to CIP Standards
Status	Posted
Comments	The team is considering comments from the initial ballot and will repost for comment in October 2017.
Deliverable	Directives, Control Center Comm Nets (CIP-012-1)
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	2
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mat Bunch & Katherine Street
PMOS Liaison	Ken Lanehome and Ash Mayfield
Affected Standards	
Last Updated	11/15/2017

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	2/10/2017	3/13/2017					
CP2 - Comment Period 2	8/14/2017	9/12/2017	12/2/2016	1/16/2017	(255)		Informal for definition
CIB - Com/Ballot 1 (Initial)	7/27/2017	9/11/2017	3/31/2017	5/15/2017	(118)		
CAB - Com/Add Ballot 2	***10/27/2017***	***12/11/2017***	8/15/2017	9/29/2017	(73)		Does not include the informal 21 day comment on Implementation Guidance ending on 12/11/2017
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/6/2018	2/15/2018	10/17/2017	10/27/2017	(112)		
PTB - Present to BOT	5/1/2018	5/3/2018	11/7/2017	11/9/2017	(175)		
Filing - Filing with Regulators	6/10/2018	6/13/2018	12/28/2017	12/31/2017	(164)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.
Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Change in Approach	6/27/2017	Team decided to create CIP-012-1 and not modiifying CIP-006 for Communcation Networks.

Project **2016-02** **Home**

Project Name	Modifications to CIP Standards
Status	Responding to Comment
Comments	The CIP-002-6 is posted for a 45-day formal comment period from September 14 - October 30. The revisions address issues from the Version 5 Transition Advisory Group (V5TAG) on the applicability of the CIP Reliability Standards to BES Cyber Systems for a Transmission Owner Control Center performing the functional obligations of a Transmission Operator.
Deliverable	Address TO Control Centers Performing Transmission Operator (TOP) Obligations.
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mat Bunch & Katherine Street
PMOS Liaison	Ken Lanehome and Ash Mayfield
Affected Standards	CIP-002-5.1a
Last Updated	11/15/2017

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	3/14/2017	4/11/2017					Added to schedule, reduced period - SDT needed feedback
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	9/14/2017	10/30/2017	12/2/2016	1/15/2017	(286)		See notes for 8/10 and 8/25.
CAB - Com/Add Ballot 2	***12/5/2017***	***1/18/2018***	3/31/2017	5/14/2017	(249)		
CAB - Com/Add Ballot 3	3/3/2018	4/16/2018	8/15/2017	9/28/2017	(200)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	5/2/2018	5/12/2018	10/17/2017	10/27/2017	(197)		
PTB - Present to BOT	8/1/2018	8/3/2018	11/7/2017	11/9/2017	(267)		
Filing - Filing with Regulators	9/1/2018	9/4/2018	12/28/2017	12/31/2017	(247)		
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Archived comments	6/10/2016	Order 822 was issued on January 21, 2016. The SC authorized posting the SAR and to request nominations for additional team members at March 9, 2016 meeting. The SAR posting ended April 21, 2016 and the SDT is reviewing the comments received. A CIP Technical Conference was held on April 19, 2016 in Atlanta. Seven additional members were appointed to the SDT at the April 20, 2016 SC meeting. Initial SDT meeting May 24-26, 2016 in Atlanta.
Added CIP Schedule for approval	7/20/2016	Update SC that schedule was approved by SDT, SDT leadership, developer, and PMOS Liaison.
Liaison Change	3/15/2017	Updated B. Murpy and A. Gallow to K. Lanehome and A. Mayfield
Developer Change	4/1/2017	Replaced Al McMeekin with Mat Bunch and Katherine Street.
Schedule Adjustment	8/10/2017	The original 5/15/2017 planned posting was accepted for 9/18 to stagger 2013-03, 2015-09, and 2015-10.
Schedule Adjustment	8/25/2017	The posting was advanced due to 2015-09 (SOL) being moved from its 9/12 posting to 9/30.

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Project	2016-02
Project Name	Modifications to CIP Standards
Status	Working to Comment Posting
Comments	The Virtualization concept comment form No. 2 was posted for a 30-day informal comment period. The team will begin drafting the applicable standards for comment and ballot in November 2017.
Deliverable	Address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, High
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mat Bunch & Katherine Street
PMOS Liaison	Ken Lanehome, Ash Mayfield, and Kirk Rosener
Affected Standards	CIP Stds. - Unknown
Last Updated	11/15/2017

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							
Nominations - DT							
QR - Quality Review	10/20/2016	10/30/2016	10/20/2016	10/30/2016			
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	3/14/2017	4/11/2017	3/14/2017	4/11/2017			
CP2 - Comment Period 2	10/6/2017	11/2/2017					Unplanned
CIB - Com/Ballot 1 (Initial)	2/1/2018	3/17/2018					
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Segmented project	8/8/2017	This fourth segment of the project was made to address all remaining V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), Obligations, Virtualization, and CIP Exceptional Circumstances.
Assign PMOS Liaison	10/12/2017	Assigned Kirk Rosener to support Ken Lanehome and Ash Mayfield.

Project	**2016-04**
Project Name	Modifications to PRC-025-1
Status	Posted
Comments	The project documents have been posted for an additional comment period and ballot due to substantive changes to the Implementation Plan. The team will meet at PG&E in Fresno, CA on Monday and Tuesday, December 18 and 19, 2018 to respond to comments. Enhancements to 025 affects entities currently implementing version 1 under the five and seven year implementation period. The first period ends October 1, 2019 and the second on October 1, 2021. Project considers the time for development and subsequent regulatory approvals.
Deliverable	PRC-025-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 9, Medium
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	Yes
Developer	Scott Barfield-McGinnis
PMOS Liaison	Charles Yeung
Affected Standards	PRC-025-1
Last Updated	11/29/2017

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	9/16/2016	9/28/2016	9/16/2016	9/28/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	9/16/2016	10/18/2016	9/16/2016	10/18/2016			
SP2 - SAR/PR/WP Posting 2	3/20/2017	4/3/2017	3/2/2017	4/1/2017	(18)		
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	7/25/2017	9/7/2017	7/26/2017	9/8/2017	1		
CAB - Com/Add Ballot 2	***10/30/2017***	***12/14/2017***	***10/24/2017***	***12/7/2017***	(6)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	1/8/2018	1/17/2018	1/8/2018	1/17/2018			
PTB - Present to BOT	2/7/2018	2/9/2018	2/7/2018	2/9/2018			
Filing - Filing with Regulators	3/7/2018	3/10/2018	3/7/2018	3/10/2018			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
SC Authorized Posting	9/14/2016	SAR and SAR SDT nominations.
Accept Baseline Schedule	7/27/2017	Accepted by PMOS.

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Project	2017-01
Project Name	Modifications to BAL-003-1
Status	Posted
Comments	On October 18 the SC: (1) authorized the posting of BAL-003-1.1 Standard Authorization Request (SAR), and assign the SAR to Project 2017-01 Modifications to BAL-003-1.1; (2) supported the SAR drafting team, nominated to address the NERC Resource Subcommittee SAR on BAL-003-1.1, to review comments received from this posting and develop one combined SAR that would be reviewed and authorized to be posted by the Standards Committee (SC); and appointed the SAR team. The team will be meeting December 19-21, 2017 at NERC to respond to comments.
Deliverable	BAL-003-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson
PMOS Liaison	Amy Casuscelli & Linda Lynch
Affected Standards	BAL-003-1
Last Updated	11/15/2017

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/19/2017	7/3/2017	6/19/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/19/2017	7/18/2017	6/19/2017	7/18/2017			By NERC RS
SP2 - SAR/PR/WP Posting 2	11/2/2017	12/1/2017	11/2/2017	12/1/2017			By NWPP FRSG
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Amy Casuscelli accepted appointment as PMOS liaison.
Assign PMOS Liaison	10/12/2017	Add Linda Lynch to support Amy Casuscelli.

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Project	**2017-02**
Project Name	Modifications to Personnel Performance, Training, and Qualifications Standards
Status	Working to Comment Posting
Comments	On SC agenda for December to approve SAR and appoint standard drafting team (SDT). No further information on standard drafting until after the December SC meeting.
Deliverable	PER-003-2, retire PER-004-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Darrel Richardson
PMOS Liaison	Mike Brytowski
Affected Standards	PER-003-1 & PER-004-2
Last Updated	11/15/2017

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR							EPR SDT appointed as SDT
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/21/2017	7/24/2017	6/21/2017	7/24/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Mike Brytowski accepted appointment as PMOS liaison.

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Project	2017-03
Project Name	Periodic Review of FAC-008-3 Standard
Status	Posted
Comments	The team had a meeting September 25, 2017 and have posted their preliminary recommendations.
Deliverable	Periodic Review Recommendations
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Al McMeekin
PMOS Liaison	Mark Pratt
Affected Standards	FAC-008-3
Last Updated	11/15/2017

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	***10/30/2017***	***12/13/2017***	***10/30/2017***	***12/13/2017***			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Mark Pratt accepted appointment as PMOS liaison.

Project	**2017-04**
Project Name	Periodic Review of Interchange Scheduling and Coordination Standards
Status	Working to Comment Posting
Comments	The team plans to have an initial posting in January 2018 followed by a meeting in Dallas, TX during the last week of February 2018 to respond to comments.
Deliverable	Periodic Review Recommendations
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)
P81 Req (2013)	N/A
Number of Directives	N/A
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Laura Anderson
PMOS Liaison	Charles Yeung
Affected Standards	INT-004, INT-006, INT-009, and INT-010
Last Updated	11/20/2017

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Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/2/2017	5/15/2017	5/2/2017	5/15/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	1/8/2018	2/22/2018					
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Charles Yeung accepted appointment as PMOS liaison.

Project	**2017-05**	**Home**
Project Name	Project 2017-05 NUC-001-3 Periodic Review	
Status	Working to Comment Posting	
Comments	The Standards Committee appointed team members July 2017. The team kicked off September 12-13, 2017 at the NERC office in DC. The team last met remotely on November 14, 2017.	
Deliverable	Periodic Review of NUC-001-3 Standard	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 9, Low (was Medium previously)	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Mat Bunch	
PMOS Liaison	Amy Casuscelli and Colby Bellville	
Affected Standards	NUC-001-3	
Last Updated	11/15/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	5/10/2017	5/23/2017	5/10/2017	5/23/2017			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1							
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	*12/4/2017*	*1/17/2018*					
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/10/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Amy Casuscelli accepted appointment as PMOS liaison.
Assign PMOS Liaison	10/12/2017	Assigned Colby Bellville to support Amy Casuscelli (new SC vice chair)

Project	**2017-06**	**Home**
Project Name	Project 2017-06 Modifications to BAL-002-2	
Status	SDT Development	
Comments	The SC on October 18, 2017 appointed the SAR team. The team will be scheduled for a future meeting date.	
Deliverable	BAL-002-3	
Deadline	N/A	
Priority in RSDP, click to see applicable Footnote	Footnote 8, Medium	
P81 Req (2013)	N/A	
Number of Directives	N/A	
No. of Guidances (see Note 2)	N/A	
Directionally consistent with IERP findings (See Note 5)	N/A	
Developer	Darrel Richardson	
PMOS Liaison	Ken Lanehome	
Affected Standards	BAL-002-2	
Last Updated	10/18/2017	

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	6/20/2017	7/3/2017	6/20/2017	7/3/2017			
Nominations - DT	7/27/2017	8/9/2017	7/27/2017	8/9/2017			Supplemental Nominations
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	6/20/2017	7/20/2017	6/20/2017	7/20/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Created Project in PTS	5/30/2017	Created Project record.
Assign PMOS Liaison	6/14/2017	Ken Lanehome accepted appointment as PMOS liaison.

Project	**2017-07**
Project Name	Stds Alignment with Registration
Status	Working to Comment Posting
Comments	The team met at NERC in Atlanta, November 14-16, 2017.
Deliverable	
Deadline	
Priority in RSDP, click to see applicable Footnote	N/A
P81 Req (2013)	
Number of Directives	
No. of Guidances (see Note 2)	
Directionally consistent with IERP findings (See Note 5)	
Developer	Laura Anderson
PMOS Liaison	Mike Brytowski
Affected Standards	
Last Updated	11/27/2017

Home

Scheduling Dates	Projected or Actual Start	Projected or Actual End	Baseline Start	Baseline End	No. of Days Ahead (Behind)	Reason for Change or Delay	Ballot or Other
Nominations - SAR / PR	8/1/2017	8/14/2017	8/1/2014	8/14/2014	(1096)		
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	8/1/2017	8/30/2017	8/1/2017	8/30/2017			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1	12/7/2017	1/6/2018	12/7/2017	1/6/2018			
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)							
CAB - Com/Add Ballot 2							
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot							
PTB - Present to BOT							
Filing - Filing with Regulators							
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Assign PMOS Liaison	7/27/2017	Mike Brytowski accepted appointment as PMOS liaison.

No.	Description
Note 1	**2015-2017 RSDP** The prioritizations here reflect those prioritizations assigned as part of the 2015-2017 Reliability Standards Development Plan (RSDP). In its approach to prioritizing Reliability Standards projects, the RSDP considered how Reliability Standard family priorities are applied to individual projects and outstanding work. Specific elements included: (1) RISC Category Rankings; (2) regulatory directives; (3) regulatory deadlines; (4) Reliability Standard requirement candidates for retirement; (5) the IERP content and quality assessments; and (6) additional considerations (fill-in-the-blank status and five-year assessment commitments). Some projects were not prioritized in the RSDP, as they were originally anticipated to be complete before the end of the first quarter of 2015, and those projects have an "N/A" designation in this column. Other projects have been added to the Project Tracking Spreadsheet that were not prioritized in the RSDP. These were added in response to regulatory directives that were issued following completion of the RSDP, and they will be prioritized according to the same process during the first quarter of 2015 according to the same process described in the RSDP. Those projects are designated as "Pending Prioritization in 1Q 2015." As discussed in the 2015-2017 RSDP, the prioritization will occur in collaboration between NERC Staff and the Standards Committee.
Note 2	Refers to guidances from regulatory orders for standards activity to consider, but that do not carry the same effect as a directive.
Note 3	In the columns at right, in some cases, an "additional ballot" is not indicated for planning purposes, but if consensus is not supported on an initial ballot, or if substantive changes occur, one will be scheduled.
Note 4	In the columns at right, there are no "plan" milestones in some cases because the project was originally planned to be complete in 2014, and the project's "actual" milestones have extended into 2015).
Note 5	In the column labeled "directionally consistent with IERP findings," directionally consistent indicates whether the Standard Drafting Team, when the project is completed, considered the recommendations from the Independent Expert Review Project and the Paragraph 81 project. After the Standard Drafting Team has considered the recommendations, the materials posted with the standards will describe the Standard Drafting Team's consideration of the findings.
Note 6	Baseline - SC Approved project schedule. Current - Standards Developer managed schedule. Proposed - Not approved, used for planning purposes. Archived-Current - Project completed or abandoned. Archived-Baseline - Project completed or abandoned. Open-Baseline - Reserved for future project. Open-Current - Reserved for future project. N/A - Scheduling is not applicable.
Note 7	**2016-2018 RSDP** The following projects are planned to continue from 2015 along with any 2015 projects that are planned to be completed in that year but need additional time. As in the 2015–2017 RSDP, the approach to prioritizing Reliability Standards projects in this RSDP addressed how Reliability Standard family priorities are applied to individual projects and outstanding work. Specific elements included: (1) RISC Category Rankings; (2) regulatory directives; (3) regulatory deadlines; (4) Reliability Standard requirement candidates for retirement; (5) the IERP content and quality assessments; and (6) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization gave primary consideration to RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.
Note 8	**2017-2019 RSDP** The approach to prioritizing Reliability Standards projects in this RSDP is consistent with previous RSDPs. Specific elements include: (1) RISC Category Rankings; (2) regulatory directives and deadlines; (3) Reliability Standard requirements recommended for retirement; (4) the IERP content and quality assessments; and (5) additional considerations (fill-in-the-blank status and five-year assessment commitments). The prioritization considers RISC category rankings, regulatory directives, and regulatory deadlines. Based on the application of these elements, this section prioritizes each Reliability Standard project as high, medium, low, or pending technical committee input.
Note 9	2018-2020 RSDP (DRAFT)
Note 10	

RSC Meeting #17-4, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	Michael Jones, Herb Schrayshuen and Quintin Lee volunteered to assist Gerry Dunbar on reviewing the Directory Manual to include A-01 (Five Year Periodic Review).	Gerry Dunbar	12/7/17	Ongoing
4.2				

DRAFT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards, Compliance, and Enforcement Bulletin

November 27–December 3, 2017

INSIDE THIS EDITION

Active Standards Postings | Other Active Comment Periods | Standards News | General Compliance and Enforcement News | Other News | Standards Subject to Future Enforcement | Board of Trustees and FERC Action | Upcoming Events | About the SC&E Bulletin

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Project 2016-02 – Modifications to CIP Standards | CIP-012-1	Additional Ballot and Non-binding Poll	12/01/17	12/11/17
Project 2016-04 – Modifications to PRC-025-1 | PRC-025-2	Additional Ballot and Non-binding Poll	12/04/17	12/13/17
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
--	--	--	--
Posted for Comment			
Project	**Action**	**Start Date**	**End Date**
Project 2017-01 – Modifications to BAL-003-1.1	Comment Period	11/02/17	12/01/17
Project 2016-02 – Modifications to CIP Standards | CIP-012-1	Comment Period	10/27/17	12/11/17

NEW Project 2016-02 – Modifications to CIP Standards |Technical Rationale and Justification and Implementation Guidance for CIP-012-1	Comment Period	11/20/17	12/11/17
Project 2016-04 – Modifications to PRC-025-1 | PRC-025-2	Comment Period	10/30/17	12/13/17
Project 2017-03 – FAC-008-3 Periodic Review | Team Recommendation	Comment Period	10/30/17	12/13/17

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Nomination Period Open for Standards Efficiency Review Teams: Nominations are being sought for new Standards Efficiency Review (SER) team members through November 30, 2017. The teams will each be focused on a different time horizon (i.e., long-term planning, operations planning, or real-time operations). However nominees should not be limited to those with expertise in any one area. Each SER team should be composed of individuals that combined represent a broad range of experience, including compliance, engineering, operations, planning, and legal. Having teams made up of cross-functional expertise will allow for more comprehensive reviews from multiple viewpoints. Nominations will subsequently be reviewed by the SER Advisory Committee. An unofficial Word version of the nomination form is posted on the Drafting Team Vacancies page and the project page.	Use the electronic form to submit a nomination. If you experience difficulty using the electronic form, contact Wendy Muller.	11/14/17	11/30/17
Comment Period Open for Regional Reliability Standards FAC-501-WECC-2, PRC-004-WECC-2, and VAR-002-WECC-2: The Western	Submit comments using the Standards Balloting and Commenting System (SBS).	11/03/17	12/18/17

Electricity Coordinating Council (WECC) has requested NERC to post the following proposed Regional Reliability Standards for industry review and comment as permitted by the NERC Rules of Procedure: • FAC-501-WECC-2 – Transmission Maintenance • PRC-004-WECC-2 – Protection System and Remedial Action Scheme Misoperation (Retirement) • VAR-002-WECC-2 – Automatic Voltage Regulators (Retirement) Unofficial Word versions of the comment forms are posted on the Regional Reliability Standards Under Development page.			
Comment Period Open for SERC Reliability Corporation Regional Reliability Standards Development Procedure: NERC is posting the proposed SERC Regional Reliability Standards Development Procedure for a 45-day procedural comment period through **January 5, 2018**. Regional standards development procedures define a Regional Entity's process for development, revision, reaffirmation, and withdrawal of a Regional Reliability Standard. An unofficial Word version of the comment form is posted on the Regional Reliability Standards Under Development Page.	Submit comments using the Standards Balloting and Commenting System (SBS).	11/17/17	01/05/18

STANDARDS NEWS

Quick Links

Register in the SBS
Projected Standards Posting Schedule
Project Tracking Spreadsheet
Standards Related Questions – Single Portal
2017–2019 Reliability Standards Development Plan
Quality Review Application

There's no additional Standards news for this week.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

Quick Links

Risk-Based CMEP
CIP V5 Transition Program
ERO Enterprise Program Alignment Process
Consistency Reporting Tool (EthicsPoint)
Risk-Based Registration Initiative
Reliability Standard Audit Worksheets
Enforcement & Mitigation: Enforcement Actions

NEW Update to 2018 ERO CMEP Implementation Plan Posted

The Electric Reliability Organization (ERO) Compliance Monitoring and Enforcement Program (CMEP) Implementation Plan (IP) is the annual operating plan used by the ERO Enterprise to implement the CMEP. Today's posting updates the 2018 ERO CMEP IP to include the Regional IP appendices.

OTHER NEWS

NEW Anticipated Resources Sufficient for this Winter, NERC Assessment Finds

Adequate generation and transmission resources are in place across the United States and Canada to meet a normal winter demand and anticipated reserve margins are at or above recommended levels, NERC's *2017–2018 Winter Reliability Assessment* finds. Assessment areas strengthened programs for reliable fuel delivery and dual-fuel generation while continuing outreach on ensuring winter preparedness.

Nomination Period Open for New RISC Members

As the terms expire for a number of Reliability Issues Steering Committee (RISC) members on January 31, 2018, volunteers are being sought from the Member Representatives Committee (MRC) and industry to serve on the RISC for two-year terms ending January 31, 2020.

The RISC is an advisory committee that reports directly to the NERC Board of Trustees and triages and provides front-end, high-level leadership and accountability for issues of strategic importance to bulk power system reliability and security. The RISC assists the Board, NERC standing committees, NERC staff, regulators, Regional Entities, and industry stakeholders in establishing a common understanding of the scope, priority, and goals for the development of solutions to these issues. In doing so, the RISC provides a framework for developing recommendations to help NERC and the industry effectively focus their resources on the critical issues needed to improve the reliability and security of the BPS. The 2016 ERO Reliability Risk Priorities report was approved by the Board and is posted on the RISC web page. The 2017 ERO Reliability Risk Priorities report will be presented to the Board for approval at its February 2018 meeting.
As described in the RISC charter, nominees for RISC should meet the following general qualifications:

- Executive-level position within the electric utility industry;
- High-level understanding and strategic perspectives on reliability risks; and
- Commitment to regular participation on the RISC in a collaborative and consensus-building manner.

The RISC holds a combination of in-person meetings and conference calls, at least once per quarter.

When determining a final slate of recommended members, the RISC Nominating Committee will evaluate nominees based on experience and qualifications, as well as diversity within the context of the entire membership of the RISC based on the following considerations:

- Geographic and international diversity, such that Eastern, Western, and Texas Interconnections, along with Canada are represented on the RISC;
- Sector, size, and asset (transmission, distribution, load, generation, etc.) diversity; and
- Diversity in professional background and experience.

If you are interested in nominating either yourself or another person, please complete the nomination form and send it to Kristin Iwanechko. **Nominations are due on or before December 15, 2017.**

STANDARDS SUBJECT TO FUTURE ENFORCEMENT

The following standards are subject to future enforcement. Please refer to the U.S. Effective Dates page for more detail:

U.S. Effective Date	Standard(s)
January 1, 2018	BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation
	PRC-006-SERC-02 – Automatic Underfrequency Load Shedding Requirements PRC-026-1 – Relay Performance During Stable Power Swings (Requirement 1);
April 1, 2018	IRO-018-1(i) – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
	TOP-010-1(i) – Real-time Reliability Monitoring and Analysis Capabilities
July 1, 2018	CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.3); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirements 3.2, 3.2.1, 3.2.2);
	MOD-026-1 – Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions (Requirements 2, 2.1–2.1.6); MOD-027-1 – Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions (Requirements 2, 2.1–2.1.5);
	TOP-001-4 – Transmission Operations
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 2)
September 1, 2018	CIP-003-6 – Cyber Security – Security Management Controls (Requirement 2, Att. 1, Sec. 2 and 3);
January 1, 2019	BAL-005-1 – Balancing Authority Control
	FAC-001-3 – Facility Interconnection Requirements
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirement 5)
January 1, 2020	PRC-026-1 – Relay Performance During Stable Power Swings (Requirements 2–4)

July 1, 2020	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (50% compliance for Requirements 2–4, 6–11)
January 1, 2021	PRC-012-2 – Remedial Action Schemes
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 6, 6.1–6.4)
January 1, 2022	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events (Requirements 3,4,7)
July 1, 2022	PRC-002-2 – Disturbance Monitoring and Reporting Requirements (100% compliance for Requirements 2–4, 6–11)
	VAR-501-WECC-3 – Power System Stabilizer (Requirement 3 has an effective date of July 1, 2022 for units placed in service prior to final regulatory approval.)

BOARD OF TRUSTEES AND FERC ACTION

There is no additional Board or FERC action to report for this week.

UPCOMING EVENTS

For information about other NERC events, such as meetings and conference calls for standard drafting teams, other standing committees, subcommittees, task forces, and working groups, please refer to the NERC calendar.

Workshops and Conferences

- Seventh Annual Human Performance Conference – March 27–29, 2017, Atlanta | **Registration Details Coming Early 2018**

Webinars

There are no webinars currently scheduled.

Standing Committee Meetings and Conference Calls

- Standards Committee Meeting – 10:00 a.m.–3:00 p.m. Eastern, December 6, 2017, Atlanta | Register
- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – December 12–13, 2017, Atlanta | Register for OC | Register for PC | Register for CIPC | Hotel Registration

Standard Drafting Team Meetings and Conference Calls

The Standards calendar provides dial-in information for the in-person meetings below. The calendar also provides information about conference calls that drafting teams may hold in addition to in-person meetings.

- Project 2015-10 – Single Points of Failure Drafting Team Meeting – November 28–30, 2017, Louisville, KY | Register
- Project 2016-02 – Modifications to CIP Standards Conference Call – Noon–2:00 p.m. Eastern, November 28, 2017 | Register
- Project 2016-02 – Modifications to CIP Standards Conference Call – Noon–2:00 p.m. Eastern, November 30, 2017 | Register
- Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, December 1, 2017 | Register
- Project 2015-09 – System Operating Limits Drafting Team Meeting – December 5–7, 2017, Atlanta, GA | Register
- Project 2016-02 – Modifications to CIP Standards Conference Call – Noon–2:00 p.m. Eastern, December 5, 2017 | Register
- Project 2016-02 – Modifications to CIP Standards Drafting Team Meeting – December 6–7, 2017, Austin, TX | Register
- Project 2016-04 – Modifications to PRC-025-1 Drafting Team Meeting – December 18–19, 2017, Clovis, CA | Register
- Project 2017-01 – Modifications to BAL-003-1.1 Team Meeting – December 19–20, 2017, Atlanta, GA | Register

ABOUT THE STANDARDS, COMPLIANCE, AND ENFORCEMENT BULLETIN

This weekly bulletin compiles a list of standards, compliance, and enforcement projects with actionable deadlines, as well as upcoming events, recently posted resources, other NERC documents posted for comment, and other relevant news and information. Please email Amy Desselle with feedback on this bulletin. The current bulletin and old bulletins are available under "Program News" on both the Standards home page and the Compliance & Enforcement home page.

If you would like to receive this bulletin or be added to the distribution list for a particular project, please contact Sandy Shiflett. For more information about any of the compliance news listed in the bulletin, please contact Tiffany Whaley.

NPCC, Inc.

~~2017~~ 2018 Scope of Work for the Regional Standards Committee (RSC)

The NPCC Regional Standards Committee (RSC), a committee of the NPCC Board of Directors (BOD), is charged with:

(a) Managing the NPCC Regional Standards Development Process.
(b) Managing the NPCC Directory and Criteria Development and Review Process.
(c) Providing consolidated NPCC Regional review and comments to existing and proposed NERC Standards in accordance with the NERC Reliability Standards Development Processes.
(d) Reviewing FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) related to Reliability Standards, by providing a forum for developing consensus. ~~viewpoints and submitting comments to FERC if necessary~~.
(e) Reviewing~~ing~~ each new and revised NERC Reliability Standard Audit Worksheet~~s~~ (RSAW~~s~~) ~~in coordination with the NPCC Compliance Committee (CC)~~ and submitting~~ting~~ comments to NERC ~~if~~as necessary.
(f) Providing consolidated NPCC Regional review and comments to the existing and proposed NERC Standards Development Processes Manual and to the NERC Rules of Procedure as they relate to Standards Development.
(g) Determining the need for and development of NERC and Regional Standards, Variances to NERC Standards, modifications to NPCC Directories and Criteria, and/or interpretations and clarifications thereof.
(h) In coordination with the CC, address issues identified through the NPCC Regional Feedback Mechanism to continually improve standards and NERC documents such as Guidelines and other technical material.
(i) Providing a forum for sharing viewpoints and opinions with the goal of achieving consensus regarding reliability attributes of various forms of industry standards, guidance and/or regulations.

Subsequent to receiving comments from NPCC stakeholders, the RSC will be responsible for submitting those consensus Regional comments to ~~FERC,~~ NERC ~~or other industry organizations as required~~.

The RSC is an open and balanced committee inclusive of all stakeholders that provide for, or are materially impacted by, the reliability of the Bulk Electric System. The RSC meetings are open to all stakeholders who want to participate and meeting materials will be publicly posted on the

NPCC Website.

Decisions of the NPCC RSC will be adopted under a sector based voting structure as described in the NPCC Amended and Restated Bylaws.

The RSC will coordinate its work through the NPCC Standards Program Area Staff which will administer actions as denoted in the NPCC Regional Standard Processes Manual and coordinate the review and submission of all standards related comments pursuant to the NERC Standards Development Processes Manual and the NERC Rules of Procedure.

The RSC will be chaired and assisted by NPCC Standards Program Area Staff along with co-vice chairs elected by the RSC from among the members of the RSC at the time the vote is taken. Chair and Co-~~v~~Vice ~~c~~Chair appointments will submitted to the~~be approved by the~~ NPCC Board of Directors for approval. The ~~c~~Co-~~v~~Vice chairs will serve a term of two years. The ~~v~~Vice-~~c~~Chair term may be extended through a motion and subsequent vote by the committee in accordance with the NPCC Amended and Restated Bylaws. An RSC Executive Committee will assist in management of the RSC and will be comprised of the Chair, the Co-Vice Chairs and two elected RSC members (the two elected RSC members will be comprised of a Canadian representative and a U.S. representative). Additionally, the two RSC members elected to the RSC Executive Committee by the RSC membership will serve for a two-year term.

Members of the RSC will be ~~nominated~~ assigned for membership in the RSC by their respective companies. NPCC RSC leadership (RSC Chairperson and Co-Vice Chairpersons) will review the nominations which will include contact information and qualifications to serve on the committee. Appointments to the RSC will be approved by the RSC Executive Committee. Each of the NPCC Sectors as defined in the NPCC Amended and Restated Bylaws will be represented on the RSC.

Commented [HS1]: Is this accurate? Is it doen this way? With review of the nominations?

Subcommittees and ad hoc Working Groups will be formed upon request of the RSC by NPCC Standards Program Area Staff. All associated scopes or charters developed, will be approved by the RSC in accordance with the most recent approved NPCC Amended and Restated Bylaws.

Each RSC Member is accountable to the members of the RSC and the NPCC Board of Directors for carrying out their responsibilities in accordance with this document.

RSC Members are to represent their companies and sectors and will also work to resolve differences with a principal goal of maintaining or improving power system reliability.

RSC Members should base their decisions on what is best for power system reliability and must consider not only what is best for their company but also what is in the best interest of the broader industry and Bulk Electric System reliability.

RSC Members should make every effort to attend scheduled meetings and when not available are required to identify and provide a qualified proxy participant. RSC business cannot be conducted in the absence of a quorum and it is essential that each RSC M~~m~~ember make a commitment to be present. A determination to recommend removal of a member shall be considered by the NPCC RSC Executive Committee if a member is excessively absent and provides no proxy for regularly scheduled meetings.

A. NPCC Regional Standards Process Responsibilities

The RSC is responsible for managing the standards process for the development of ERO Regional Standards, Violation Risk Factors (VRFs), Violation Severity Levels (VSLs), definitions, variances, interpretations and clarifications in accordance with the NPCC Regional Standard Processes Manual and the NPCC Amended and Restated Bylaws pertaining to quorum and voting rules. The RSC is responsible for ensuring the quality of all Standards-related materials.

The RSC will be available to advise the NPCC BOD on Regional Standard related matters.

B. NPCC Directory and Criteria Process Responsibilities

The RSC provides oversight for the development of NPCC Directories and the criteria within each document. The RSC will provide guidance to all NPCC Committees, Task Forces and Working Groups regarding the development of NPCC documents including Directories, Criteria Procedures and Guidelines.

The RSC will be available to advise the NPCC BOD on Directory and Criteria related matters.

C. NERC Reliability Standards Responsibilities

The RSC will:

- Provide a forum for NPCC review, coordination and submission of NPCC comments to existing or proposed NERC Reliability Standards when posted for NERC "Open Process Review."
- Provide a forum for NPCC to participate, solicit and provide Regional comments on Standard Authorization Requests (SARs) and their respective Reliability Standards in accordance with the NERC Standard Development Processes Manual.
- Provide a forum for NPCC to participate in, and be kept aware of emerging risks from the NERC Reliability Issues Steering Committee (RISC)
- Provide a forum for NPCC to participate, solicit and provide Regional comments to the ~~Enhanced~~ Periodic Review Process for standards.
- Identify prospective reliability issues associated with new or revised NERC Reliability Standards and their potential impact on the NPCC Region, (i.e., Regional differences).
- Propose solutions or guide the development of the NERC Reliability Standards through effective and timely comments and soliciting NPCC participation on the SAR, Periodic Review and Reliability Standard Drafting Teams.
- Develop and maintain a ~~W~~web-~~B~~based Database for tracking and scheduling Standards development activities from a Regional perspective.
- Target a wide range of participants across the NPCC membership during the Standard commenting process in order to achieve broad regional consensus. Develop databases and e-mail list servers to engage more members and to elicit different perspectives.
- Follow up on proposed and adopted changes to the NERC Standard Development Processes Manual and Rules of Procedure as they apply to Reliability Standards, and provide NPCC members with basic information (or assistance with the NERC Website) for a common understanding of the processes.
- Coordinate the activities of NPCC members on Standard Drafting Teams, and encourage NPCC representation on all Standard Drafting Teams.

- Coordinate with the CC any NPCC input to ~~the ERO Compliance Guidance Policy in~~CMEP Implementation Guidance documents in accordance with the ~~CMEP NPCC~~CC~~Implementation Guidance~~ ~~P~~process for submitting implementation guidance to NERC.

D. FERC Activities Affecting Standards

The RSC will review FERC Orders, Rulings and Notice of Proposed Rulemakings (NOPRs) relating to ERO and Regional Reliability Standards. The RSC will discuss, develop regional consensus positions, and if necessary, develop recommended comments for consideration by the NPCC Board of Directors to FERC on behalf of NPCC.

When requested, participate in technical conferences hosted by NERC, FERC or other Regions on topics of importance to power system reliability.

Northeast Power Coordinating Council, Inc.
Regional Standards Committee
Work Plan for Calendar Years 2017~~7~~8-2018~~8~~9

The following Regional Standards Committee (RSC) Work Plan activities for the calendar years of 2017~~7~~8 - 2018~~8~~9 will be consistent with the NPCC 2018~~7~~7 and 2018~~8~~9 Business Plans and Budgets, Organizational and Strategic Goals, both approved and in draft, and will also continue to be supportive of the ongoing ~~cost effective enhanced~~ periodic reviews, ~~and results based~~ standard development and standards efficiency review activities. Also, the Work Plan is responsive to the NERC Reliability Standards Development Process and ERO strategic goals. ~~In 2017~~8 ~~2018~~9, ~~expedited standards~~ review ~~project schedules as a result of FERC Orders Directives and the NERC Board of Trustees goal of achieving a "steady-state" for reliability standards will be the focus of the~~ RSC.

NPCC Reliability Standards Committee Program Responsibilities (related to Standards)

To carry out its standards related responsibilities defined in the NPCC RSC Scope of Work, the RSC will perform the following activities:

1. Monitor NERC's Reliability Issues Steering Committee (RISC) risk profiles and other reliability related issues and priorities for potential incorporation into NERC standards, for removal from standards or for potential incorporation into guidelines or other non-standards based solutions. Provide and coordinate NPCC's input into those standard development and guideline decisions.
2. Coordinate and provide input to the development and prioritization of ERO reliability standards within the NERC Reliability Standards Development Plan through active regional participation in the ~~Enhanced~~ Periodic Review Standing ~~Committee~~Review Team.
3. Review and support the ERO ~~results-based~~ standards efficiency initiative and ongoing standards development work ~~towards the ERO goal of a 'steady-state' of standard development~~ which is defined to be a core set of results-based standards achieving an adequate level of reliability. ~~and subject to little change by P~~providing ongoing input to the ~~Enhanced~~ Periodic Review Template used to determine the efficacy of standards. ~~Promote the steady-state standards initiative throughout the Northeast.~~

~~3.~~

4. Continue to provide input ~~to the development of a model~~ for consideration of costs in NERC's Standards Development program.

~~4. [Cost of Risk Reduction Analysis (CRRA) first draft and pilot.]~~

~~5.~~ Oversee, and participate in the regional standards development process and base any development, revision or retirement of NPCC Regional Reliability Standards on the reliability related needs of the Region or continent-wide ERO standards such as~~:~~

~~a.~~5. the ongoing ~~R~~revision of NPCC PRC-006-NPCC-~~0~~1 Underfrequency Load Shedding

~~b. Revision of NERC PRC-006-2 Underfrequency Load Shedding (Quebec Regional Variance)~~

6. Engage in the ~~newly approved~~ NERC Compliance Guidance Policy process. Support the inputs through the NPCC Compliance Committee by providing technical and policy related opinions as necessary.
7. Coordinate NPCC Regional Standards development activity with NERC Standards development activity to ensure resources are available for efficient and effective standards development and implementation.

Commented [HS1]: NERC considers itself as having achieved "steady state"

Commented [HS2]: Clarify the input going into the standards and guideline process. Or do you intend to input to the RISC?

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8. Coordinate NPCC participation in the review and the revision of NERC Standards and addressing reliability directives from FERC's Orders and any Provincial regulatory directives through the Enhanced Periodic Review process. Specifically, and of the highest importance:
    a. ~~Reliability Standards activity resulting from a future FERC Order 860 on Geomagnetic Disturbances (GMD)~~
    b. ~~Single Points of Failure~~
    ~~c.~~a. Modifications to CIP Standards
    d. ~~Activity resulting from a future FERC Order on Cyber Security Supply Chain Management~~
    e. ~~Establish and Communicate System Operating Limits~~
    ~~f.~~b. and any other similar activity which may evolve during the course of the year.
9. Address emerging issues FERC has identified with the NPCC Regional Standard Processes to promote consistency and support of the ERO ~~One~~ Enterprise Alignment~~model~~.
10. Conduct thorough reviews of all NERC Standards being developed or revised and coordinate timely comments within the NPCC Region based on reliability needs, results based requirements, ~~Paragraph 81, FERC directives~~ and ~~Enhanced~~ Periodic Reviews.
11. Develop and submit Standard Authorization Requests (SARs) for revisions when necessary to improve ~~a~~ Standards and address reliability related issues for approved or draft Standards utilizing input from the NPCC Regional Feedback Mechanism to improve the quality and efficacy of standards.
12. Develop ballot recommendations or "issues statements" for RSC members for all NERC Standards under development.
13. Review and develop ballot recommendations for all NERC formal interpretations to Standards.
14. Identify candidates for NERC Standards Drafting Team and other standards or guideline development groups ~~members~~ from the NPCC region to ensure regional representation during the development of the respective Standards.
15. Provide guidance to NPCC ~~r~~Regional Standard Drafting Teams in critical areas of results-based Standards, Violation Severity Levels, and Violation Risk Factor development as well as ensuring quality.
16. Respond to FERC and Provincial filings and interrogatories on issues related to regional Standards.
17. Serve as a liaison for the Northeast Region to the NERC Reliability Issues Steering Committee for all new and emerging reliability risks to the BES.
18. Participate in the proceedings of various NERC groups to contribute to the continual improvement of NERC Standards and processes. These groups include but are not limited to:
    a. NERC Standards Committee (SC)
    b. NERC Standards Committee Process Subcommittee (SCPS)
    c. NERC Project Management Oversight Subcommittee (PMOS)
    d. NERC Functional Model Advisory Group (FMAG)
    e. NERC SAR and Standards Drafting Teams (SDTs)
    f. NERC Reliability Issues Steering Committee (RISC)
    ~~f.~~g. NERC Standards Efficiency Review (SER) Teams
19. Manage the development and revision of the ~~r~~Regional ~~r~~Reliability Directories including C~~c~~riteria clarifications as necessary and review all NPCC ~~c~~Criteria to ensure consistency with NERC or regional Reliability Standards.
20. Promote the NPCC ~~c~~Criteria as augmenting and providing specificity to NERC standards requirements or addressing reliability risk issues not addressed~~covered~~ in existing NERC standards. Coordinate efforts with the NPCC Compliance Committee to facilitate further development of the NPCC Criteria Compliance Enforcement Program (CCEP) via Phase 2 of the Directory Project which was initiated to reformat the criteria section of each Directory into measurable NERC-style requirements.
21. Develop proposed standards and standard clarifications utilizing regional technical committees as assigned by the NPCC Reliability Coordinating Committee, RSC or as identified through the NPCC Regional Feedback Mechanism.
22. Work with the NPCC CC to develop the necessary compliance elements of the ~~r~~Regional Standards, for example, Violation Severity Levels (VSLs).
23. Implement the NPCC Cost Effective Analysis Procedure and apply it to Directories being revised or developed, as needed, and promote and participate in the NERC ~~Cost of Risk Reduction Analysis (CRRA) application~~cost effectiveness approach to the ERO draft continent-wide Standards.
24. Review NERC SARs, Standards, and interpretations, and provide comments as well as participate in NERC stakeholder processes.

Commented [HS5]: Is this a real projet?

Commented [HS6]: Already covered above

25. Ensure that the appropriate NPCC Task Forces review NERC Standards-related issuances, and provide input to support development of a NPCC consensus opinion.
26. Solicit technically qualified candidates from NPCC stakeholder companies to participate on each of the NERC Standard Drafting Teams and additional members to the regional drafting teams. Ensure sufficient regional representation exists on the drafting teams.
27. Educate and notify NPCC Region stakeholders and regulators about issues related to Standards development.
28. Participate in two scheduled NPCC Compliance and Standards Workshops
29. Participate in the revision and redrafting of the NERC Rules and Procedures and other documents related to standards development such as, but not limited to:
    a. The NERC Functional Model Working Group (FMWG)
    b. The NERC Regional Standards Group (RSG)
    c. The NERC Standards Committee (SC)
    d. The NERC Standards Committee Process Subcommittee (SCPS)
30. Coordinate implementation of the NERC Standards development processes and NPCC Rregional Standard processes and recommend revisions as necessary.

Commented [HS7]: Already covered above

NPCC Reliabilityregional Standards Committee Program Responsibilities (related to Directory Criteria)

1. Coordinate Directory Development activities with the regulatory authorities in the U.S. and applicable Provincial authorities.
2. Identify the need for new or modified NPCC Directories and the Criteria, Guidelines and Procedures within pursuant to Section 313 of the NERC ROP responsibilities
3. Oversee a broad review for the development, or modification, or retirement of Directories in accordance with the NPCC Directory Development and Revision Manual
4. Coordinate Directory cCriteria requirements with rRegional and NERC Standards requirements to ensure no inconsistencies exist and identify potential areas for improvements.
5. Develop filings for the Directories for the New York State Public Service Commission to fulfill obligations for the "Carve-out" outlined in Order 672 for mandatory adherence to more stringent regional criteria for New York State.
6. Develop filings of Directories as required with the Provincial authorities as per the various Memorandums of Understanding.
7. Communications
    a. Announce development activities pertaining to the NPCC Reliability Directories and NPCC guidance documents which will enable users, owners and operators of the Bulk Power System in the Region to be aware of and apply the NPCC regionally-specific criteria.
    b. Identify future rRegional Standard development or retirement opportunities by developing a set of rRegional rReliability Directories incorporating the ERO Reliability Standards, Rregional Standards and rRegionally-specific more stringent cCriteria.

Commented [HS8]: Already covered in #2

Commented [HS9]: Do the Directories still incorporate the standards?

The activities listed in this work plan are based on the current planned execution of the NERC Reliability Standards Development Plan (RSDP), proposed strategic direction of the NPCC BOD and NERC BOT as well as additional Directives from the FERC Orders. Changes to these programs, the NERC RSDP, the NERC Rules of Procedure, or the NPCC Standards or Directory processes may necessitate changes to listed activities, including revised scheduling of the activities, removal of certain activities, and/or the addition of activities. If significant changes occur during the course of the year, the RSC Work Plan will be revised in advance of the NPCC Board of Director's annual review and will be forwarded to the NPCC Board of Directors for approval.

NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
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Redlined for RSC Review
December 7, 2017

Northeast Power Coordinating Council, Inc.

Directory Development and Revision Manual

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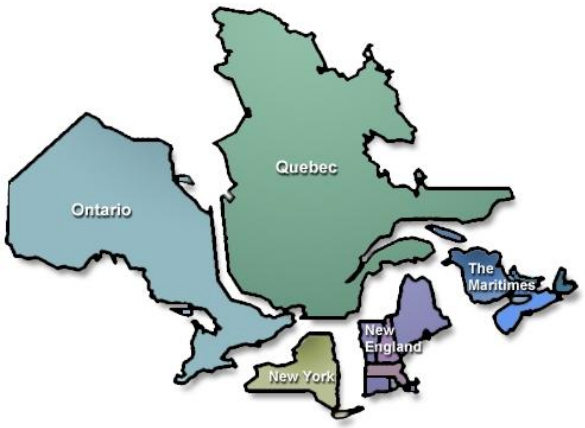
Process for the Review and Approval of Criteria, Guidelines, and Procedures



Approved by the Reliability Standards Committee

~~October~~ Month ~~26~~xx, ~~2011~~ 2017

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Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	xx/xx/2017	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01

DIRECTORY DEVELOPMENT and REVISION MANUAL

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I. EXECUTIVE SUMMARY

~~The purpose of the Northeast Power Coordinating Council, Inc. ("NPCC") is to enhance the reliability of the international, interconnected bulk power system in Northeastern North America through the development of more stringent and regionally specific criteria.~~

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. One of the ways NPCC carries out its mission is through the development of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.

NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

This document provides guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory, when retiring or consolidating an existing Directory and also clarifies the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project. Individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

NPCC also recognizes the industry concern surrounding the cost of maintaining the more stringent or more specific NPCC criteria contained within the NPCC Directories and the~~–~~ NPCC Board of Directors has expressed strong support for the appropriate balance between the incremental reliability benefit achieved by the criteria versus the cost to maintain or implement those criteria.~~.~~

Accordingly, the fundamental review methodology of the NPCC Cost Effectiveness Analysis Procedure (CEAP) has been incorporated into the Directory Development and Revision Manual.

This document also contains the process for the review and approval of Criteria, Guidelines, and Procedures that have not been incorporated into a Directory and remain as standalone documents outside of any Directory.~~.~~

Commented [HS1]: Here is what the website says about NPCC and its mission. Not sure all of this is needed, but this sentence leaves the impression the only mission is to" enhance the reliability".

Northeast Power Coordinating Council, Inc. (NPCC) is a 501(c) (6) not-for-profit corporation in the state of New York responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. NPCC carries out its mission through (i) the development of regional reliability standards and compliance assessment and enforcement of continent-wide and regional reliability standards, coordination of system planning, design and operations, and assessment of reliability, (collectively, "regional entity activities"), and (ii) the establishment of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria (collectively, "criteria services activities"). NPCC provides the functions and services for Northeastern North America of a cross-border regional entity through its regional entity division, as well as regionally-specific criteria services for Northeastern North America through its criteria services division.

II. BACKGROUND

NPCC Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and procedures;- within each Directory NPCC's reliability criteria has been reviewed and translated to ~~insure~~ ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

Each Directory also contains former Guideline – Type -"B" -and Procedure – Type "C" documents which have been renamed as Appendices and are functionally relevant to the documents criteria. ~~Consistent with NPCC Document A-01 *Criteria for Review and Approval of Documents* t~~The ~~purpose of an~~ Appendix ~~continues to~~ supports the achievement of system performance related to the criteria and the consistent implementation, interpretation and monitoring of the criteria requirements.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Committee (RCC) in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics. During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Also during Phase 1, Functional Model language was introduced and the corresponding "~~-~~B-" Guidelines and "~~-~~C"~~-~~ Procedures were incorporated into each Directory as Appendices. The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC~~-~~ style requirements which will promote the NPCC regional criteria as more specific or more stringent within each

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Directory. Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated ("~~A~~A"- ~~-~~Criteria, "B"- ~~-~~Guideline, or "C"-~~-~~Procedure). The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices. A link to the Directory Flowchart and the Directory Mapping documents is provided in the References section of this manual.

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~~The existing~~Most of NPCC's ~~Several~~ ~~'~~"B~~'~~" Guideline and "~~'~~C~~'~~" Procedure documents ~~have either been~~were transferred to Directories as Appendices in support of the relevant criteria~~. or wil~~Those B and C documents that were not incorporated into a Directory ~~transferred~~ ~~l~~ remain ~~ed~~ as standalone ~~"'B'" Guideline and "'C'" Procedure~~ documents~~. at the conclusion of the Directory project.~~

III. APPLICABILITY OF NPCC CRITERIA

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The requirements of an NPCC Directory apply only to those facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in NPCC M~~m~~ember~~external~~ tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements. ~~NPCC will not enforce compliance to the NPCC Directory requirements on any entity that is not an NPCC Full Member.~~

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IV. TASK FORCE ROLES AND RESPONSIBILITIES~~:~~

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With the development of the Directories it has been recognized that in certain cases more than one Task Force is responsible for the content of a Directory and coordination

between Task Forces is necessary. ~~the jurisdictional boundaries of Task Force ownership have been crossed and additional guidance when coordinating Directory review among Task Forces is necessary.~~

Commented [HS4]: Do we really mean areas of responsibility of Task Forces have been crossed? Jurisdictional seems to not be the right word to me.

In general, revisions and clarifications to a Directory shall be coordinated by the Lead Task Force of the document. Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document. A link to the NRAP documents is provided in the ~~References~~References section of this manual.

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The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision. Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

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1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, along with a request for the RSC to authorize a Cost Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a

new Directory to the appropriate Task Force. The Lead Task Force responsible for developing the new Directory shall draft an initial version of the document consistent with the Directory template in Attachment A.

The RSC working with NPCC Staff shall utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory via the Cost Benefit Analysis (CBA) section of the CEAP. After the RSC reviews and approves the CBA the Lead Task Force shall post the draft Directory to the NPCC Open Process for 45 days.

At the conclusion of the ~~45 day~~45-day Open Process period, the Lead Task Force will discuss the comments submitted. The Lead Task Force shall also determine if the Cost Effectiveness Analysis (CEA) portion of the CEAP shall begin and where appropriate, request the RSC to initiate the CEA

If the responses to comments received on the draft result in substantive changes to the document, the revised draft shall be reposted to the Open Process for a successive 45 day posting period. The process of comment review, revision and re-posting for comment continues until no substantive modifications to the draft Directory are made.

The RSC in accordance with the CEAP will use the responses to the CEA survey to develop a recommendation based on the cost effectiveness of the proposed Directory. After the RCC approves both the draft Directory and the CEAP the draft Directory is submitted for ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

The process for establishing a new Directory is represented below in Figure 1:

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Figure 1: New Directory

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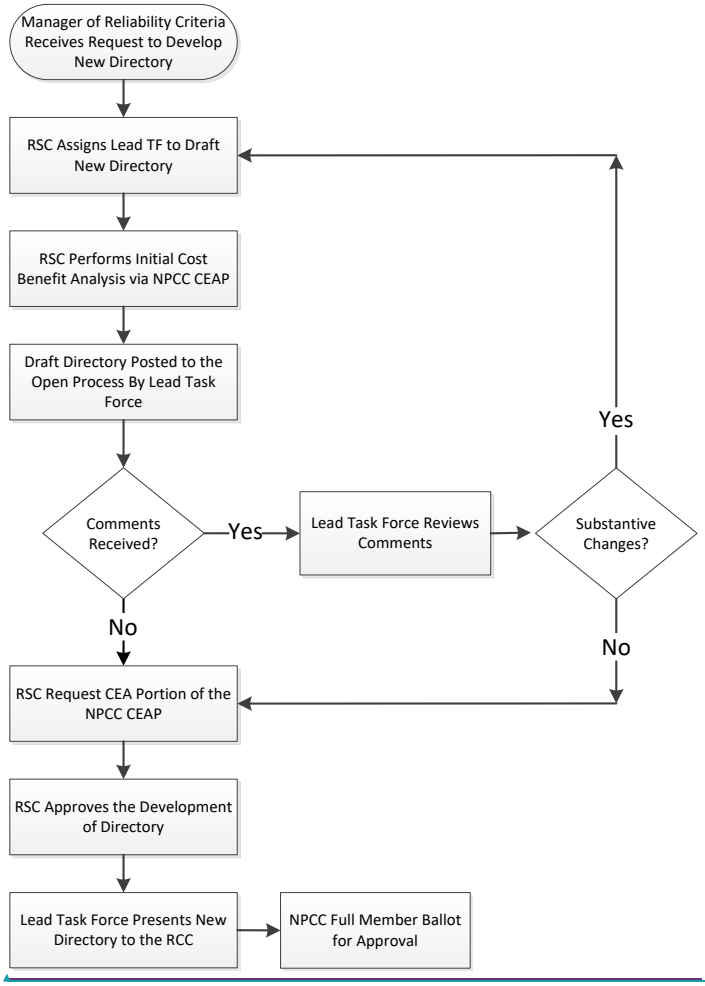
[1] Approval of a new or revised Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.



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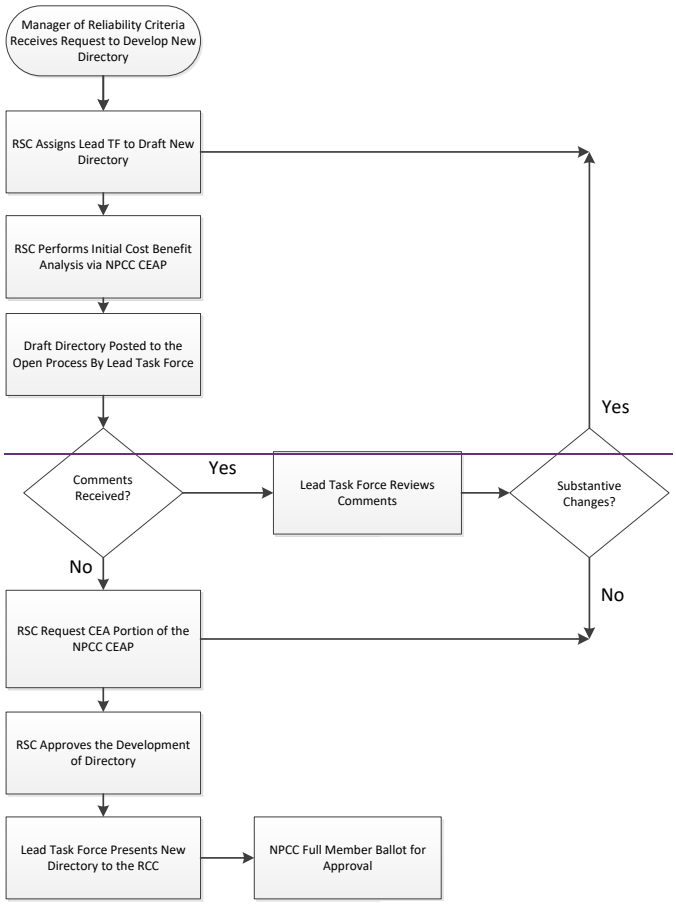
Manager of Reliability Criteria Receives Request to Develop New Directory
RSC Assigns Lead TF to Draft New Directory
RSC Performs Initial Cost Benefit Analysis via NPCC CEAP
Draft Directory Posted to the Open Process By Lead Task Force
Comments Received?
Yes
Lead Task Force Reviews Comments
Substantive Changes?
Yes
No
No
RSC Request CEA Portion of the NPCC CEAP
RSC Approves the Development of Directory
Lead Task Force Presents New Directory to the RCC
NPCC Full Member Ballot for Approval

2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document. The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

In ~~general~~general, it is not anticipated that revisions to the criteria section of a Directory will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory revision via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA for the proposed revision with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the revision process.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary. The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

At the conclusion of the ~~45 day~~45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.

Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval. Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2: Revisions to Criteria

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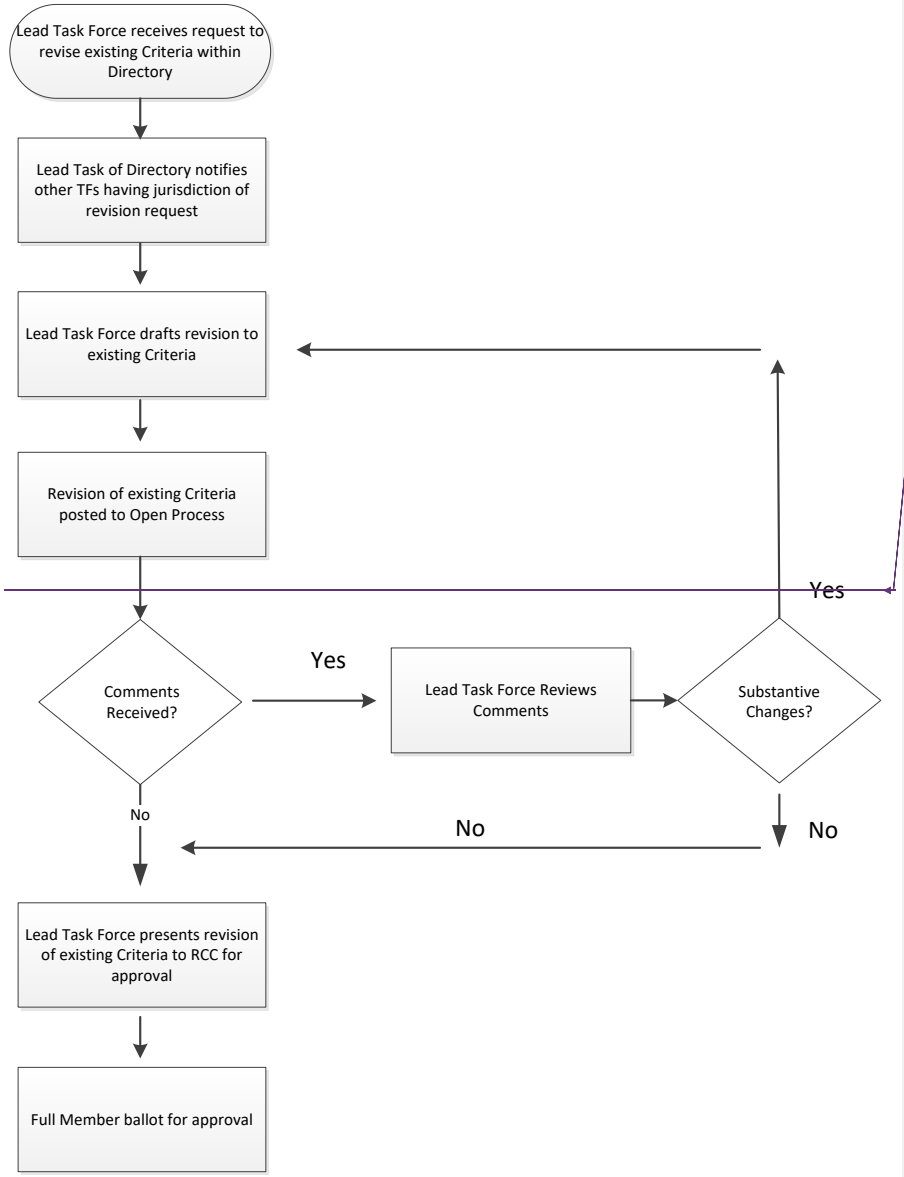

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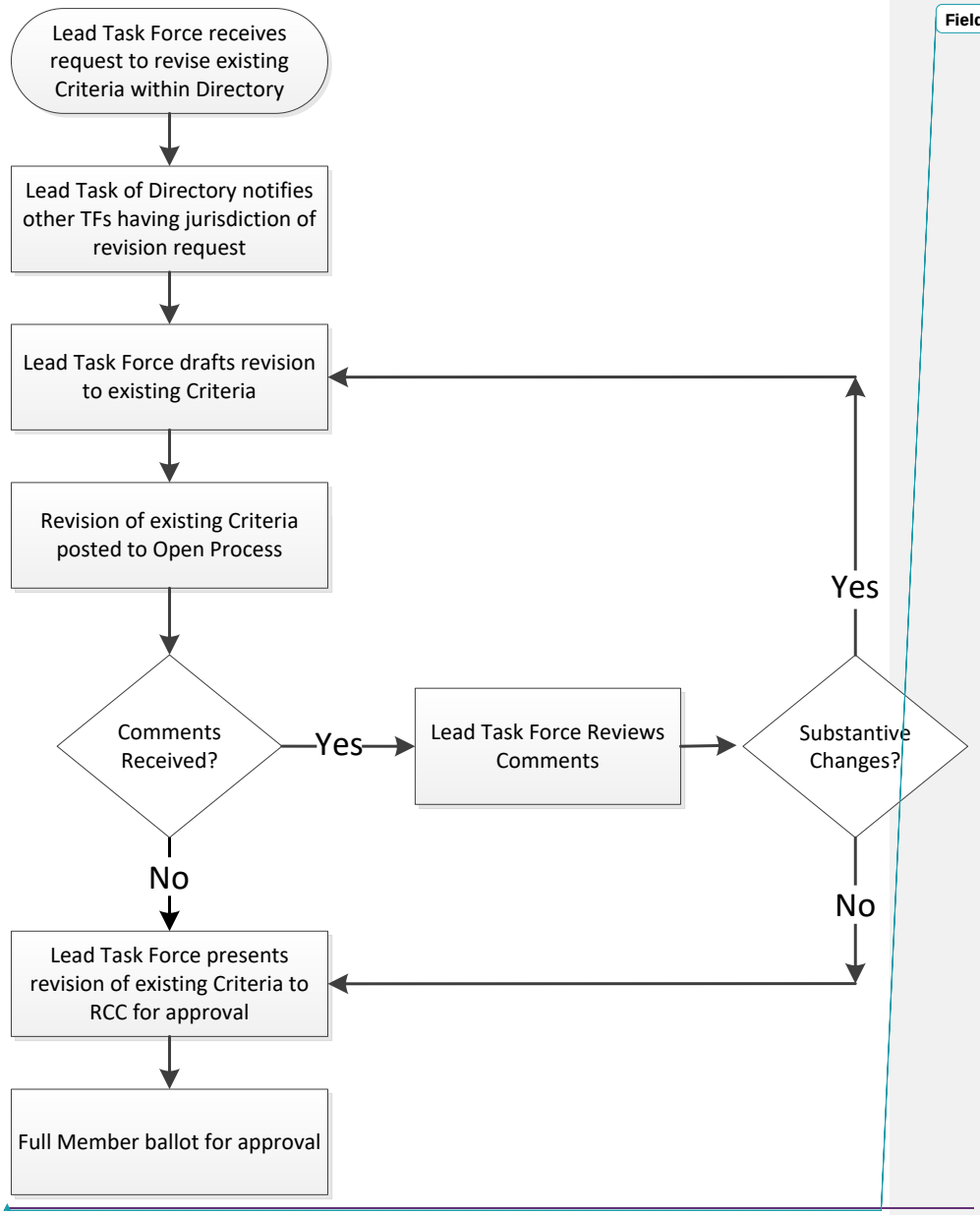

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b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

Any NPCC Full Member may request an Appendix within a Directory to be revised or retired. Revisions or retirements of Appendices shall only require Task Force approval.

A request to revise or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix. The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise or retire an appendix has been received.

After the Task Force responsible for the revised Appendix request reviews the subject Appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the revised or retired Appendix to the NPCC Open Process review for 45 days. The Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the ~~45 day~~45-day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the revised or retired Appendix. If the responses to the comments received on the revised or retired Appendix result in substantive changes to the Appendix, then the Directory containing the revised or retired Appendix shall be reposted to the Open Process for a successive ~~45 day~~45-day review period by the Lead Task Force of the entire Directory. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired Appendix shall be voted on by the Task Force responsible for the Appendix.

The lead Task Force for the Directory containing the revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the Reliability Coordinating committee for informational purposes.

The process for revisions to the Appendices within an existing Directory is represented below in Figure 3:

Figure 3: Revisions to Appendices

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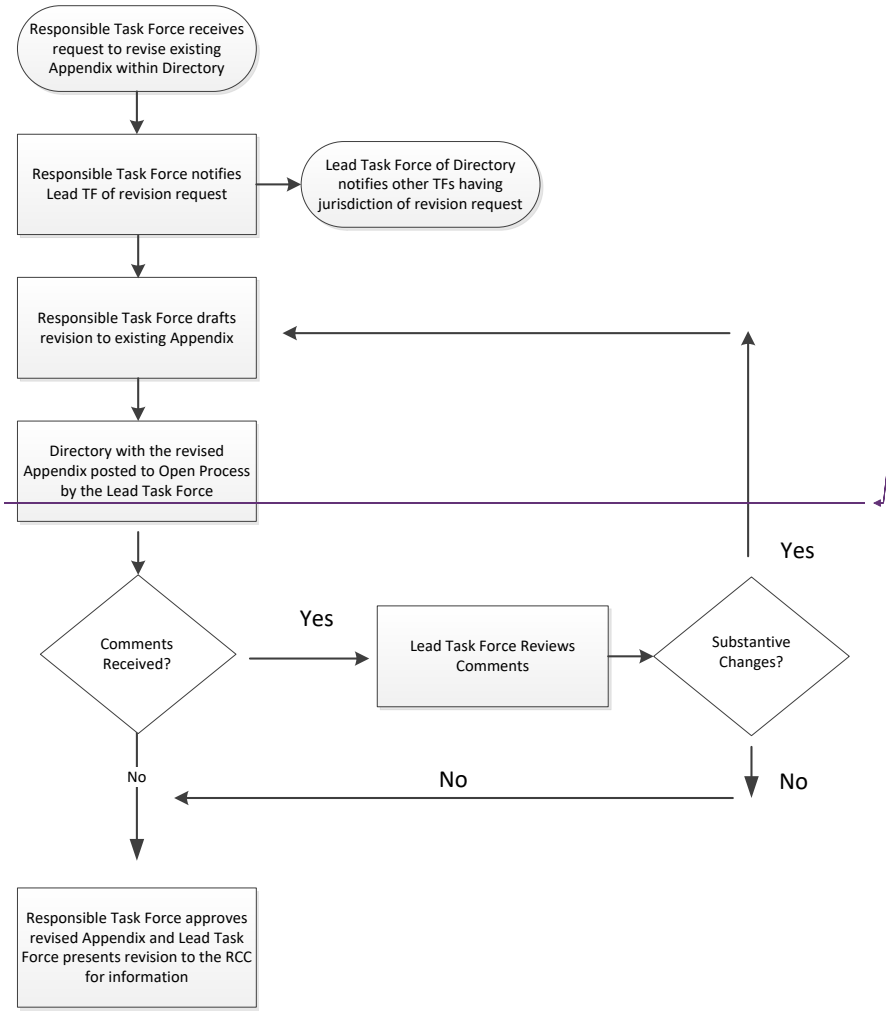

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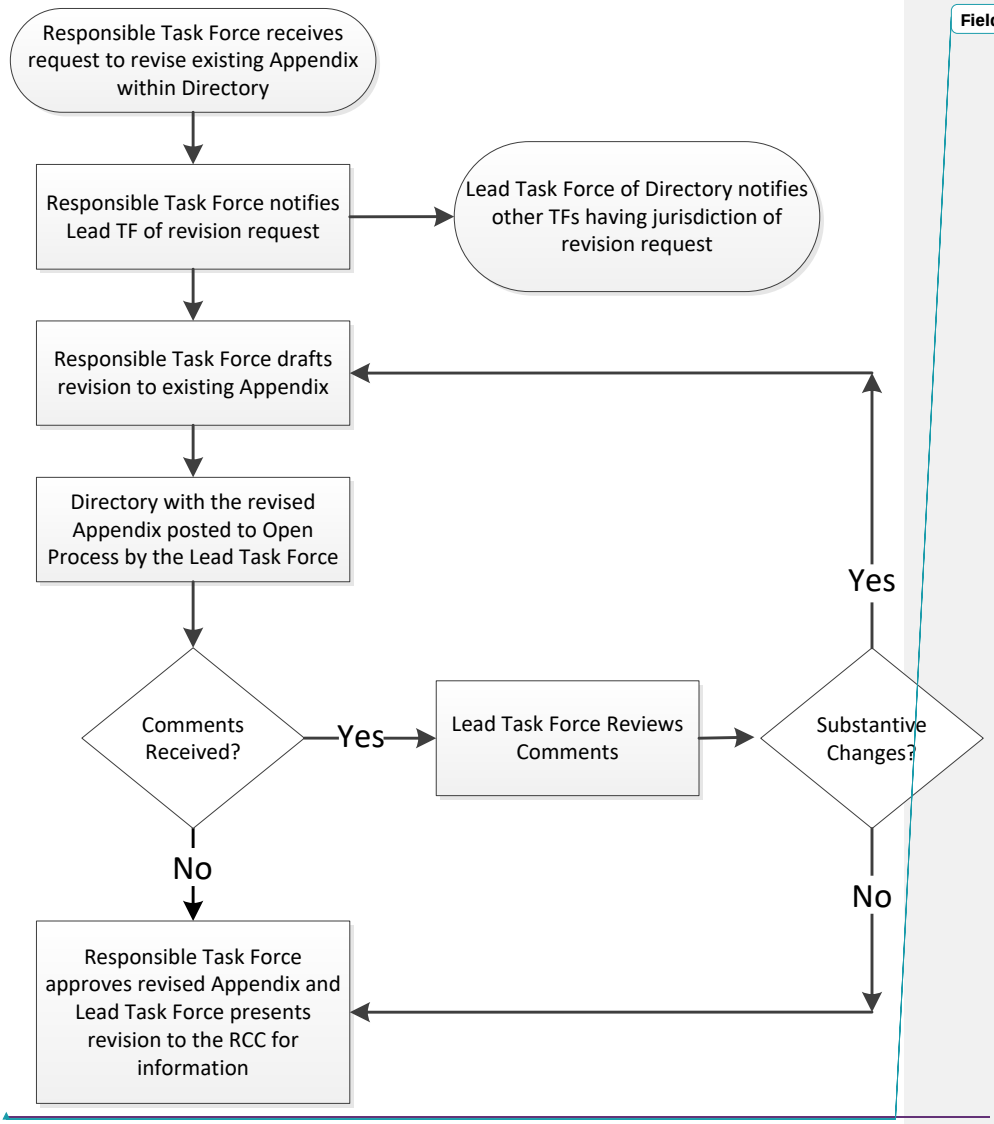

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c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document. Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a Glossary term be revised or added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term to be revised resides or will reside. When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

In ~~general~~general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed or revised Glossary term via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA review of the proposed or revised Glossary term with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

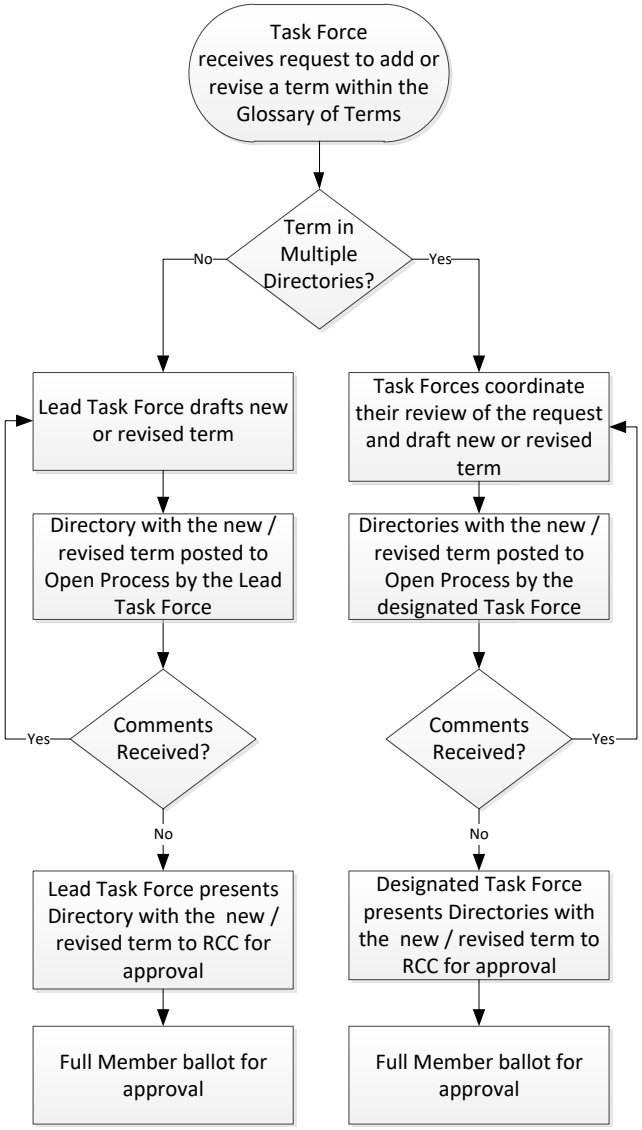
After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the ~~45 day~~45-day Open Process, if responses to~~-~~ comments received on the new or revised term result in further~~-~~ substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory. Alternatively, if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC approval the Directory containing the new or revised term will be balloted by the Full Members. Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the Glossary of Terms is represented below in Figure 4:

Figure 4: Revisions to the NPCC Glossary of Terms



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d. Withdrawal Of Revision Requests

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Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request by notifying the NPCC Manager of Reliability Criteria.

3. Directory Retirement

Upon identification of the need to retire an existing Directory, the Lead Task Force responsible for the Directory shall notify the NPCC Manager of Reliability Criteria of its proposal to retire a Directory.

The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. The NPCC Manager of Reliability Criteria shall post the proposal, along with supporting documentation to the NPCC Open Process for 45 days.

At the conclusion of the ~~45 day~~45-day Open Process, the Lead Task Force will review the comments submitted and post responses on the NPCC Open Process portal. The NPCC Manager of Reliability Criteria shall present the proposal to retire the Directory to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the proposal to retire the Directory will be submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation to retire the document.

4. Maintenance of Links and Errata

The maintenance of Links and the correction of errors found in a Directory or its Appendices shall be the responsibility of NPCC Standards staff. An error may be classified as Errata provided its correction does not change the scope or intent of the Directory and has no impact on the end user of the Directory.

Errata and Link revisions are updated as needed and require only the Lead Task Force approval prior to publishing and notifications to the applicable regulatory jurisdictions if required.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

The Manager of Reliability Criteria will forward an approved *Request for Criteria Clarification* to the NPCC Task Force designated as the Lead Task Force for the subject Directory. The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a ***Request for Criteria Clarification*** has been received. The Lead Task Force shall also forward the request to the affected Task Force.

The Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria within 60 calendar days. The Manager of Reliability Criteria shall post the ***Request for Criteria Clarification***, along with the responses provided by the Lead Task Force to the NPCC Open Process for 45 days.

[2] The Request for Clarification Form is included in Appendix B of this document.

The Lead Task Force will consider all comments received on the posted clarification and if necessary revise the clarification based on these comments. If the Lead Task Force revises the clarification substantively on the basis of comments received the clarification shall be reposted to the NPCC Open Process for a successive 45 day posting period.

The Manager of Reliability Criteria will coordinate a response to all commenters on behalf of the Lead Task Force. The Lead Task Force response to a Directory clarification request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate any ambiguity.

The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ~~insure~~ ensure that it is clear and provides the requested explanation without expanding on the criteria.

The Lead Task Force response to a ***Request for Criteria Clarification*** shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the clarification to the NPCC website.

The detailed results of the ***Request for Criteria Clarification*** shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

The process for a Criteria Clarification Request is represented below in Figure 5:

Figure 5: Request for Criteria Clarification

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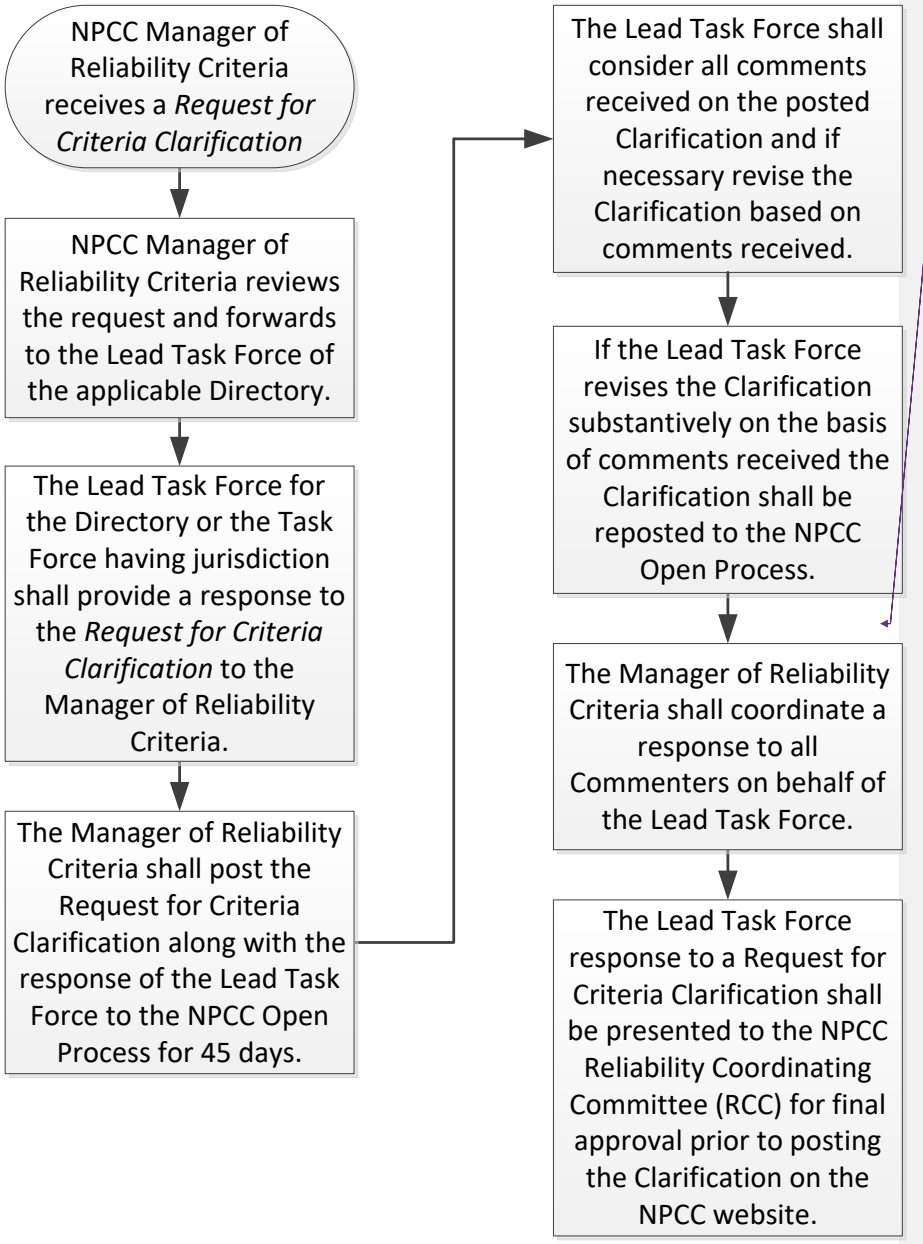

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b. APPEALS

Any NPCC Full Member that has submitted a ***Request for Clarification*** may appeal the rendered Task Force response.

The appellant shall submit a written complaint to the NPCC Manager of Reliability Criteria describing the substantive or procedural action or inaction associated with the Clarification Request process.

The appellant shall also describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary NPCC Standards Staff and Lead Task Force resources, the NPCC Manager of Reliability Criteria shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint.

VII. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL

The NPCC Directory Development and Revision Manual will be reviewed at least once every five (5) years or more frequently if required.

A notification of a pending RSC review and re-approval of the Manual shall be posted on the NPCC website. All revisions to this Manual shall be posted to the NPCC Open Process Review for 45 days.

The Regional Standards Committee (RSC) shall respond to all comments received and shall have final approval over the revised document.

VIII. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES

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Introduction

The Process for Review and Approval of Criteria, Guidelines, and Procedures was formerly outlined in NPCC Document A-01 *Criteria for Review and Approval of Documents.*

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The Directory Project has consolidated most NPCC Criteria-Type “A” documents, Guideline-Type “B” documents, and Procedure-Type “C” documents into the Directories.

This ~~Criteria~~section is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all remaining -NPCC Criteria-Type “A” documents, Guideline-Type “B” documents, and Procedure-Type “C” documents. ~~NPCC documents have been divided into three categories, Document Type "A", Type "B" and Type "C". (See Appendix A for Process Flow Diagram and detailed description of process steps)~~

Document, Criteria - Type "A"

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General Description

Type "A" documents, with approval by the NPCC Full Member ~~Representatives,~~Representatives; describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force- on a periodicity~~frequency~~ to be determined by the lead Task Force or initiated at the request

of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. ~~Acceptance is determined~~implied ~~if no comments are received by NPCC. Comments are submitted through the NPCC web site.~~ The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval. ~~This final ballot approval will be conducted either at a scheduled RCC meeting or via email and electronic ballot.~~

In its~~-~~ review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved, the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for ballot~~vote~~, with a recommendation for its adoption. Approval of ~~an~~ NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes. See Appendix C for further details on the entire NPCC Open Process.

For ~~new or~~ modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted with an effective date or implementation plan, as noted on the document itself with the following statement:

"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

The approved and adopted Type "A" document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list

Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for non-compliance issues.

Commented [HS5]: The periodicity may also come from the document not the committee. For instance A-10.

Commented [HS6]: "implied" is too loose

Commented [GJD7]: I don't think this sentence is necessary.

Commented [GJD8]: Not necessary.

Commented [HS9]: In the judgment of the TF? Should we do something more along the lines of "errata" rules.

Commented [GJD10]: Not necessary.

Commented [QDL11]: Is it still possible to add a 'new' "A" document? If not this can be deleted.

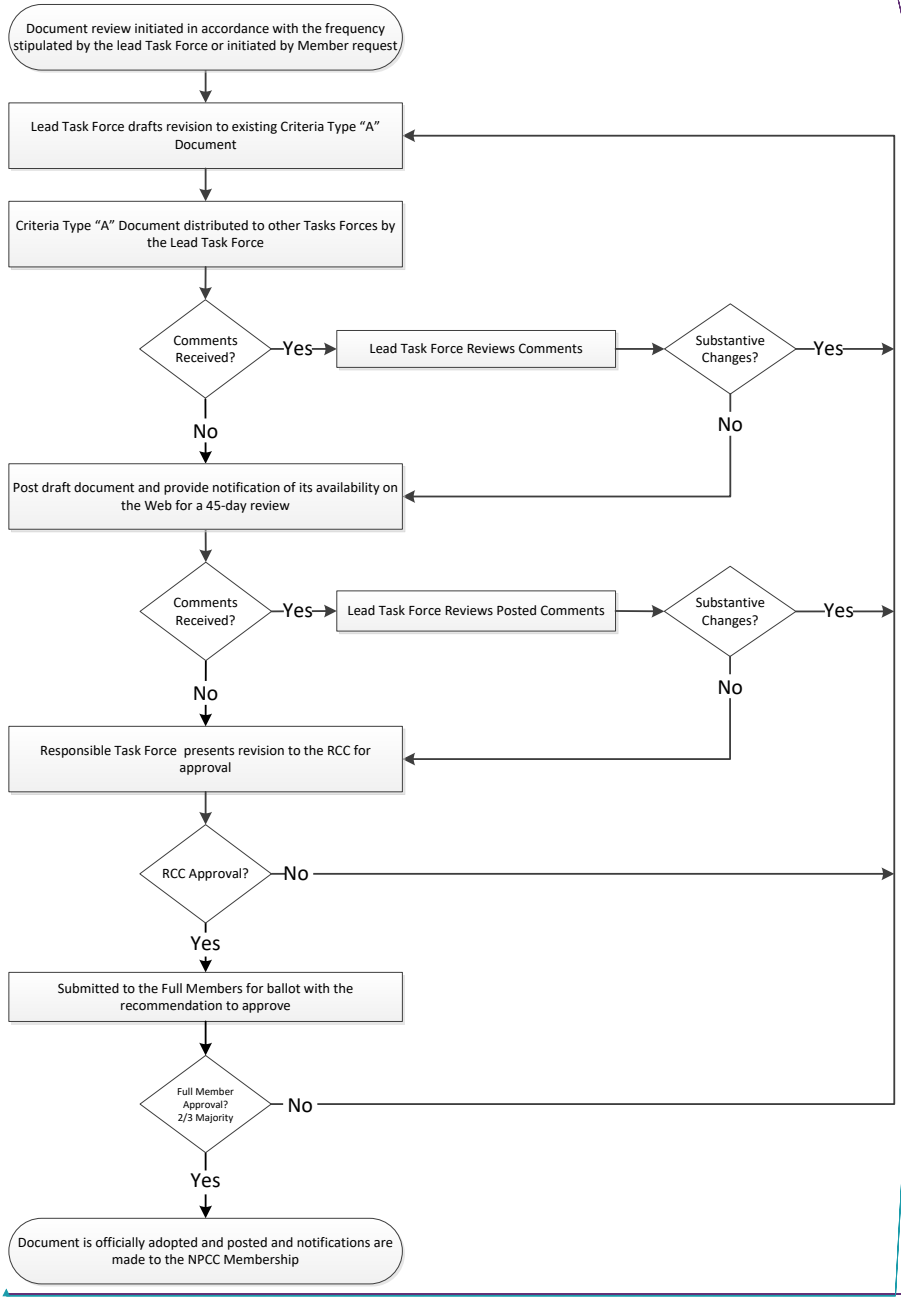
Gerry's comment….I recommend retaining…..although unlikely it is possible.

Commented [HS12]: How about relative to implementation schedules, rather than non-compliance.

Retiring a Type “A” document requires following the same steps as the revision process.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 6:

Figure 6: Revisions to Document, Criteria - Type "A"



Commented [GJD13]: This chart is excellent Quintin….however one suggested change:

In the case of an A Criteria document revision….. the Lead TF is generally the only TF involved….unlike a Directory where the Lead TF of the Directory may need to coordinate the review with other TF's who have jurisdiction over an Appendix in the Directory.

Accordingly, I think this flow chart can be tightened up a bit.

No need to distinguish between Lead TF and responsible TF since they are one in the same.

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Document~~s~~: Guideline ~~-~~ Type "B" and Procedure-Type "C"

General Description

Type "B" documents~~, with approval by the Reliability Coordinating Committee,~~ are ~~the guides or~~ guideline documents~~s for the achievement of acceptable system performance which implement criteria of Type "A" documents~~.

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements.

Review and Approval

Any NPCC Full Member may request a Guideline-Type "B" or a Procedure-Type "C" document be revised or retired. Revisions or retirements of Guideline-Type "B" or Procedure-Type "C" documents shall only require Task Force approval.

A request to revise or retire a Guideline-Type "B" or a Procedure-Type "C" document shall be submitted to the Task Force responsible for the document. ~~The Task Force responsible for the document shall notify the Lead Task Force that a request to revise or retire the document has been received.~~

~~The Lead Task Force shall be responsible for notifying all Task Forces which have jurisdiction over the document that a request to revise or retire the document has been received.~~

~~After the Task Force responsible for the document reviews the subject document they will forward the draft revised document to the Lead Task Force.~~ The ~~Lead~~ Task Force shall be responsible for posting the revised or retired document to the NPCC Open Process review for 45 days. ~~The Lead Task Force will limit the comments solicited to only the subject document.~~

The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45--day posting.

At the conclusion of the ~~45-day~~ Open Process, the ~~Lead~~ Task Force responsible for the B or C document shall consider all comments received and incorporate comments as appropriate.~~will forward the comments submitted on the document to the Task Force responsible for the revised or retired document.~~ If the ~~responses to the~~ comments received on the revised or retired document result in substantive changes to the document, then the document shall be reposted to the Open Process for a successive 45-

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Commented [GJD14]: I notice we didn't describe 'retiring' an A Criteria document in the section above.

Seems inconsistent…and I think we should address.

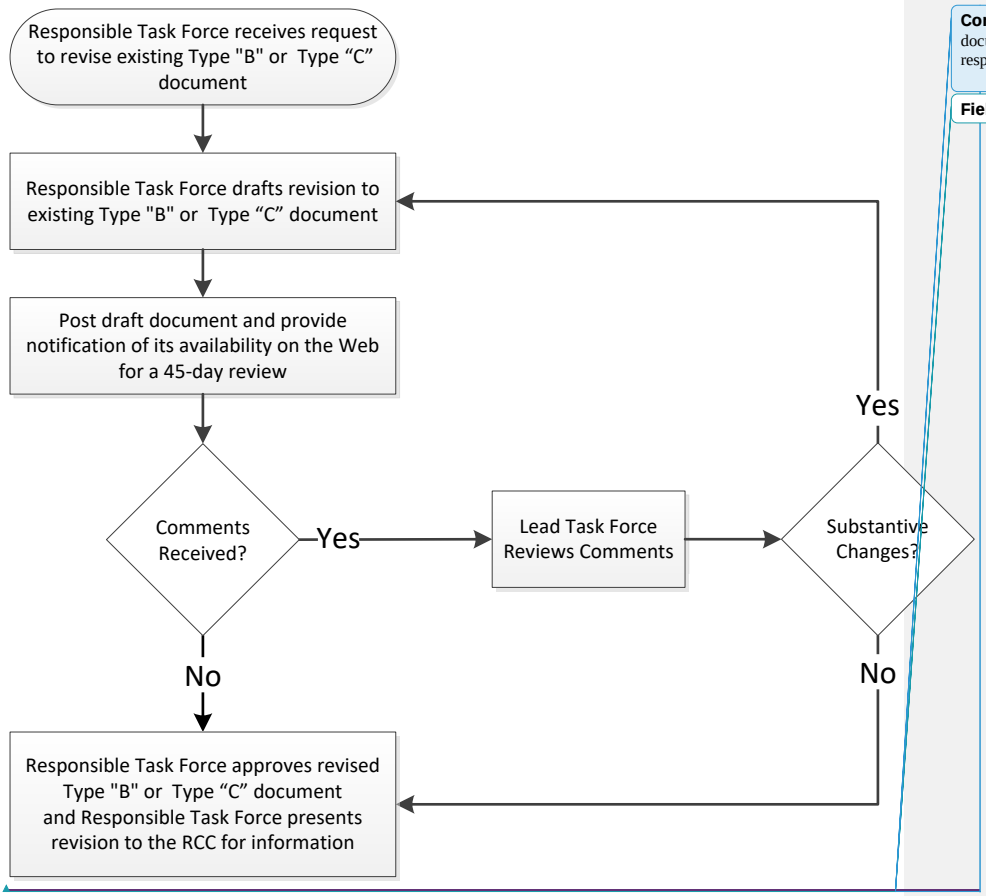
Commented [GJD15]: Again in the case of standalone B and C documents there is no distinction between Lead TF and the TF responsible for the document….they are the same.

day review period by the ~~Lead~~ Task Force responsible for the document.~~.~~ Alternatively, if there are no substantive changes which would require additional postings, the revised or retired document shall be voted on by the Task Force responsible for the document.

The ~~lead~~ Task Force responsible for the document shall distribute the document to the Reliability Coordinating committee for informational purposes.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 7:

Figure 7: Revisions to Guideline - Type "B" and Procedure-Type "C" Documents



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Commented [GJD16]: Again in the case of standalone B and C documents there is no distinction between Lead TF and the TF responsible for the document….they are the same.

Field Code Changed

~~Type "B" documents are prepared and revised by the designated lead Task Force, on a frequency to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the NPCC web site. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "B" document is presented by the lead Task Force to the Reliability Coordinating Committee for~~

approval either at a scheduled RCC meeting or via email and electronic ballot. The document will then be posted on the NPCC website and distributed to the membership via a documented and maintained distribution list. See Appendix C for further details on the entire NPCC Open Process.

Should the RCC determine that the document cannot be approved the RCC will return the document to the lead Task Force.

Members may request the lead Task Force, at any time, to review and revise the Guidelines, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for outstanding issues.

Document, Procedure Type "C"

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General Description

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Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements of Type "A" and "B" documents.
Review and Approval

Type "C" documents are prepared and revised by the designated lead Task Force, on a frequency to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Acceptance is implied if no comments are received by NPCC. Comments are submitted through the NPCC web site.

The lead Task Force may invoke an expedited posting period for a "C" document if necessary to address implementation issues as identified by the lead Task Force.

Expedited postings will be for no less than 30 days.

The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required which would require an additional posting(s), the Type "C" document will be considered and voted on for final approval by the lead Task force and is then distributed for informational purposes to the Reliability Coordinating Committee and the other Task Forces. (Formal adoption by the Reliability Coordinating Committee or the NPCC Full Member Representatives is not required for Type "C" documents).

The document will then be posted on the NPCC website and distributed to the membership via a documented and maintained distribution list with the next Reference Manual Revision. See Appendix C for further details on the entire NPCC Open Process.

~~The maintenance of Links, contact lists and the correction of errors found within NPCC documents ("A' Criteria, 'B' Guidelines and 'C' Procedures) shall be the responsibility of the NPCC Standards staff.~~

~~An error may be classified as Errata provided its correction does not change the scope or intent of the language.~~

~~Errata and Link revisions are updated as needed and require only the approval of the lead Task Force prior to publishing.~~

~~NPCC staff will also maintain a record of the change on the Record of Revision.~~

~~Members may request the lead Task Force, at any time, to review and revise the Procedures or References, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for outstanding issues.~~

~~Lead Task Force: Task Force on Coordination of Planning~~

~~Reviewed for concurrence by: TFCO, TFSP, TFSS, CC, and TFIST~~

~~Review frequency: 4 years~~

~~**IX.**References:~~

1. ~~https://www.npcc.org/Standards/Directories/Directory_Flowchart.pdf.~~
2. ~~https://www.npcc.org/Standards/Directories/Directory_Mapping.pdf.~~
3. ~~https://www.npcc.org/Library/NRAP/Forms/Public%20List.aspx~~

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APPENDIX A - DIRECTORY FORMAT TEMPLATE

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		**Effective Date**	**New**

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

Objective: State the reliability objective that this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

Effective Date: Identify which parts of the Directory become effective on which dates.

Background: Provide information related to this creation or revision of this Directory, e.g., which "A", "B" or "C" documents are mapped into this Directory; the general basis of the Directory, etc.

Applicability: Identify the entities that are assigned reliability requirements and/or which facilities need to conform to the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

List the requirements and criteria that the applicable entities or facilities must comply with.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of ~~Non Compliance~~Non-Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a ~~45 day~~45-day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

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NPCC, Inc.

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

NPCC Request for Criteria Clarification

Note: ~~an~~An Interpretation cannot be used to revise a Directory.

Request for Criteria Clarification of a Directory
Date clarification request submitted: Date clarification response provided:
Contact information for person requesting the clarification:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number:
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this clarification:
Identify the material impact to your organization or others caused by the lack of clarity within this Directory:

Submit completed Request for Criteria Clarification forms to the NPCC Manager of Reliability Criteria.

Clarification: Response to Request for Clarification of Directory XX for the XXXX Corporation
The following clarification of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

~~Appendix C – NPCC Open Process for Regional Reliability Criteria Development and Review~~

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~~*Step 1 Initiation of the Open Process Review (Boxes 1, 2, 3, and 4)*~~

~~*(Reference the, Figure 6 Flowchart at the end of this Appendix)*~~

~~**The NPCC Open Process for Regional Reliability Criteria Development and Review can be initiated a number of ways:**~~

~~**A comment is submitted through the Open Process on the NPCC web site identifying an issue that could initiate a review.** *(Box 1)* **The Task Forces will review the comment and respond to it with a recommendation.** *(Box 2)*~~

~~**An NPCC Member, Task Force, CC, or other party may identify a reliability need that is currently not addressed in the existing set of documents.** *(Box 4)*~~

~~**Once a NPCC Open Process for Review is initiated for a Document, it is identified and tracked in the NRAP Report.** *(Box 3)*~~

~~*Step 2 Document Review and Revision (Boxes 5, and 6)*~~

The designated lead Task Force as identified in the NRAP or as charged by the Reliability Coordinating Committee (RCC) to draft a new document will develop it and build a consensus within the Task Force. *(Box 5)*

The document, once approved by the lead Task Force for public release, will be posted using the NPCC Open Process for a comment period. This comment period will begin once notification is made to the industry of the posting and comments will be accepted through the NPCC website for a period not to exceed 45 days. Notification will be given to neighboring Regions, whose reliability might be impacted by NPCC's Criteria, and their review of the proposed Criteria will be accommodated and submittal of their comments encouraged. *(Box 6)*

Step 3 Industry Comments on the Posted Document (Boxes 7, 8, 9, 10, 11, 12, 14, 15, 17, and 18)

The industry and neighboring Regions whose rReliability may be affected hiave 45 days to submit their comments to the proposed document. *(Box 7)*

At the end of the comment period the lead Task Force will review the comments and reach consensus on how to address the comments and decide whether further revision to the document is necessary. *(Box 8)* Also as part of this revision the lead Task Force must ascertain if the revisions are substantive enough to require another posting.. *(Box 11)*

- The lead Task Force will then post the responses to the comments received to the NPCC Open Process for industry review. *(Box 9)*

- The document is revised as necessary into a "final" draft. *(Box 10)*

- If the document is a *"C" (a Procedure)* document, the document is voted on by the lead Task Force and if not approved further work is required and notification is posted. *(Box 14, 15, 17 and 18)*

- *If the document is a "C" (a Procedure)* document *(Box 12)*, and approved by the lead Task Force, *go to Step 6 (Box 16)*

Step 4 Gaining other Task Force and RCC Approval (Documents "A" and "B" Type Criteria or Guidelines only) (Boxes 12a 13, 19-25)

- Following the posting of the Document, the affected Task Forces will arrange to review the document and approve it. *(Boxes 12a and 13)*

- If the document is not acceptable as is and further revision is requested the document will be returned to the lead Task Force with the specific recommended revisions. *(Box 19)*

~~This revision, if accepted by the lead Task Force, may result in another Open Posting and notifications to neighboring Regions whose reliability might be impacted. *(Box 20)*~~

~~If the NPCC Task Forces have all signified their acceptance and approval of the document, it will be forwarded to the RCC for its review. *(Box 21)*~~

~~The RCC will vote on the document at its next scheduled meeting and if there are issues outstanding, the RCC will make specific recommendations to the lead Task Force and request that further work be done. Notification is posted. *(Box 22, 23 and 24)*~~

~~*If the document is approved by the RCC and is a "B" Type, (a Guideline Document)(Box 25), go to Step 6 (Box 26)*~~

~~*Step 5 Gaining Full Member Representative Approval (Document "A" Type Criteria only) (Boxes 27, 28, 31, and 32)*~~

~~Upon approval of an "A Type" document by the RCC, the Document is submitted to the NPCC Full Member Representatives noting the recommendation by the RCC to approve. *(Box 27)*~~

As outlined in the NPCC By-Laws approval of an NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes.. *(Box 28)*

If the document is not approved, any submitted comments by the Full Member Representatives will be forwarded along with the document back to the lead Task Force for further work and notification is posted. *(Box 31 and 32)*

Step 6 Document is Officially Adopted (All Documents) (Boxes 16, 26, 29, 30, 33, 34, and 35)

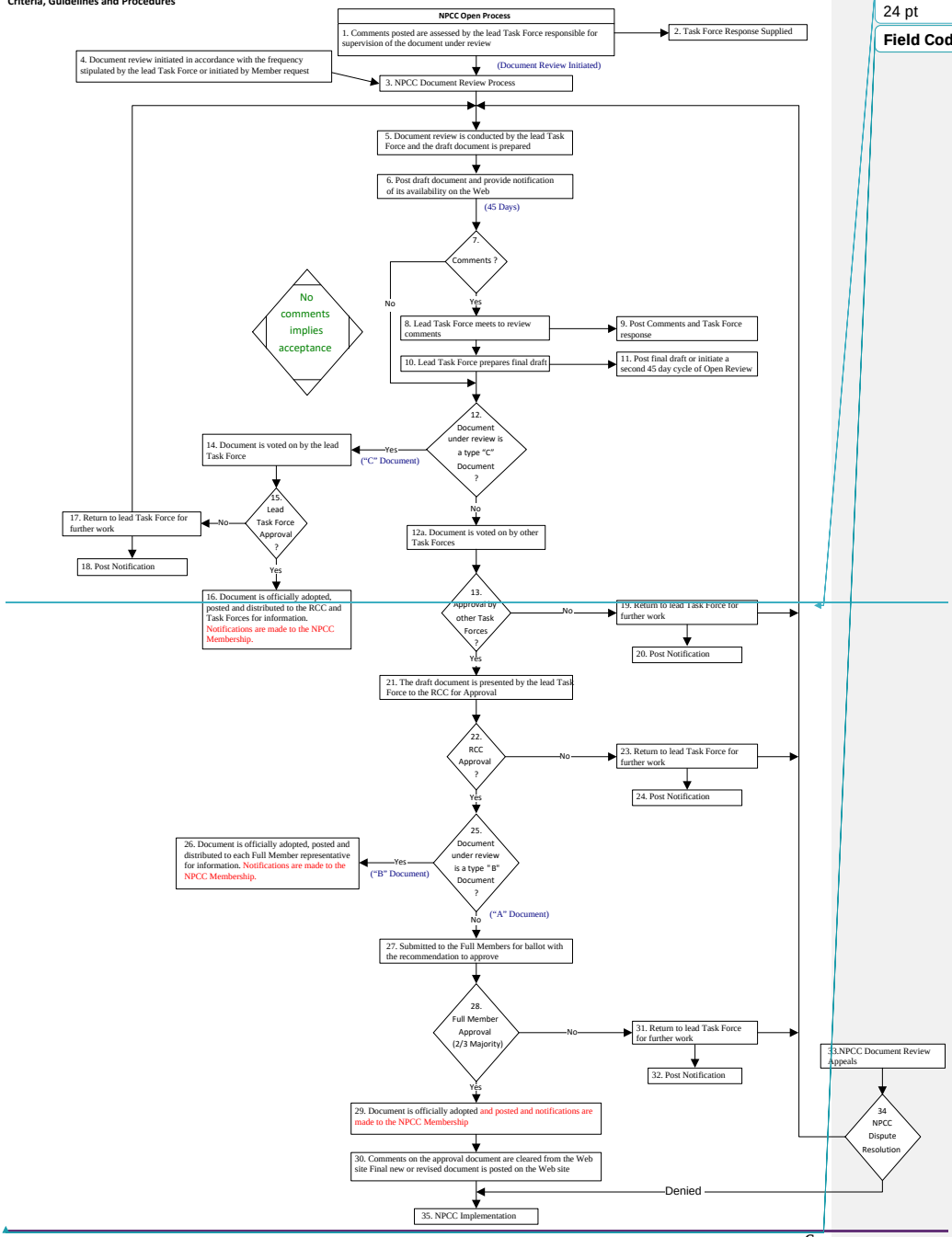
Document is officially adopted along with any implementation plan for compliance and notifications are made to the NPCC Membership. *(Boxes 16, 26, and 29)*

Document is posted on the public portion of the NPCC website, replacing the old document if a revision is made. NPCC Staff will also update the NRAP as required to show the next scheduled review date. *(Box 30)*

The requirements and procedures in the revised or new document are implemented, as stated in the implementation plan, or continued as required by the document. *(Box 35)*

~~AT ANYTIME~~ANY TIME ~~DURING THE PROCESS AND PRIOR TO IMPLEMENTATION THE DOCUMENT IS SUBJECT TO THE NPCC DISPUTE RESOLUTION PROCESS. *(BOX 33 AND 34)*~~

NPCC Open Process of Criteria, Guidelines and Procedures



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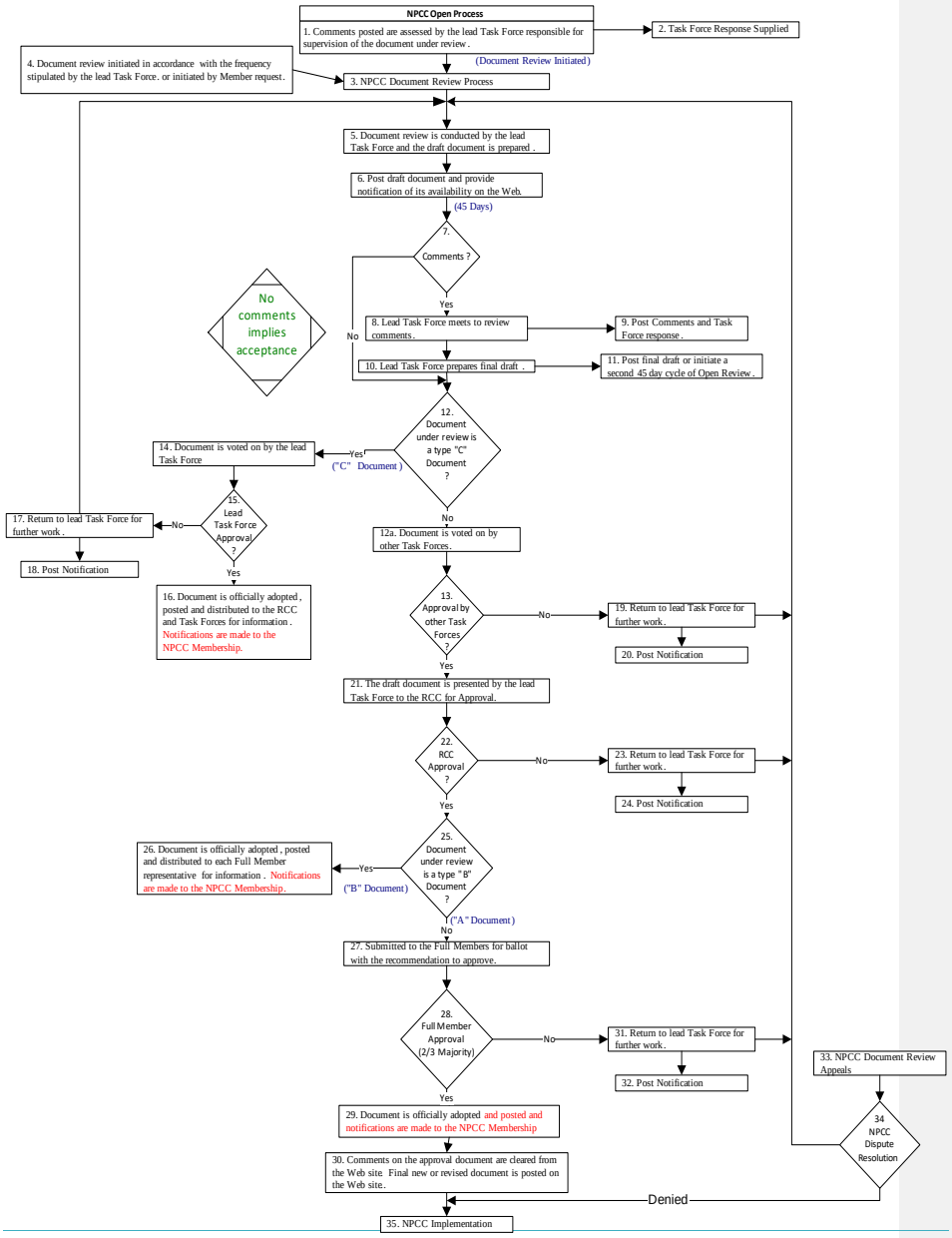
NPCC Open Process of
Criteria, Guidelines and Procedures



NPCC, Inc.

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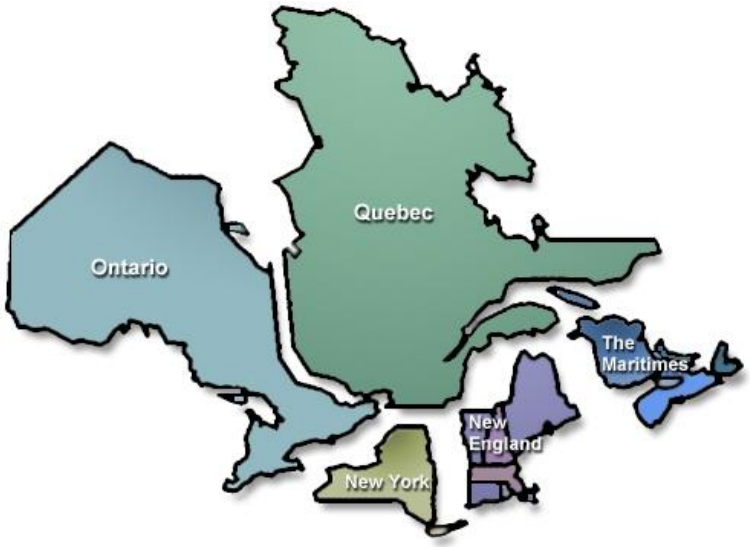
Clean for RSC Review
December 7, 2017

Northeast Power Coordinating Council, Inc.

Directory Development and Revision Manual

&

Process for the Review and Approval of Criteria, Guidelines and Procedures



Approved by the Reliability Standards Committee

Month xx, 2017

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0	10/26/2011	Effective Date	New
1	12/5/2013	Revised	Revised Interpretation Approval Process
2	10/03/2014	Revised	Added NPCC CEAP Considerations
3	xx/xx/2017	Revised	Added Process for Review and Approval of Criteria, Guides, and procedures from Document A-01 to permit retirement of A-01

DIRECTORY DEVELOPMENT and REVISION MANUAL

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I. EXECUTIVE SUMMARY

The Northeast Power Coordinating Council, Inc. (NPCC) is responsible for promoting and enhancing the reliability of the international, interconnected bulk power system in Northeastern North America. One of the ways NPCC carries out its mission is through the development of regionally-specific criteria, and monitoring and enforcement of compliance with such criteria. NPCC Directories have been developed in order to provide a consistent and comprehensive set of reliability requirements for the Northeast, while consolidating related information for NPCC Criteria, Guidelines, Procedures as well as FERC and NERC approved Regional Standards into one document.

This document provides guidance to NPCC Task Forces and NPCC Full Members when establishing a new or revised Directory, when retiring or consolidating an existing Directory and also clarifies the roles and responsibilities of the NPCC Task Forces responsible for Directory content.

The NPCC Regional Standards Committee (RSC) working with the lead Task Force for each Directory has overall responsibility for managing the Directory project. Individual Directories are under the control of a lead NPCC Task Force which is responsible for coordinating review among all other Task Forces which have jurisdiction over either a portion of the criteria or one or more of the Appendices in the Directory.

NPCC also recognizes the industry concern surrounding the cost of maintaining the more stringent or more specific NPCC criteria contained within the NPCC Directories and the NPCC Board of Directors has expressed strong support for the appropriate balance between the incremental reliability benefit achieved by the criteria versus the cost to maintain or implement those criteria.

Accordingly, the fundamental review methodology of the NPCC Cost Effectiveness Analysis Procedure (CEAP) has been incorporated into the Directory Development and Revision Manual.

This document also contains the process for the review and approval of Criteria, Guidelines, and Procedures that have not been incorporated into a Directory and remain as standalone documents outside of any Directory.

II. BACKGROUND

NPCC Directories have been developed consistent with the NPCC Bylaws which provide for the establishment of regionally specific reliability criteria, guidelines and procedures; within each Directory NPCC's reliability criteria has been reviewed and

translated to ensure that the criteria is not inconsistent with the ERO standards as required by the NERC Rules of Procedure.

Each Directory also contains former Guideline – Type "B" and Procedure – Type "C" documents which have been renamed as Appendices and are functionally relevant to the documents criteria. The Appendix supports the achievement of system performance related to the criteria and the consistent implementation, interpretation and monitoring of the criteria requirements.

Phase 1 of the Directory Project was initiated by the NPCC Reliability Coordinating Committee (RCC) in order to demonstrate consistency with NERC Standards and to effectively group documents together according to functional topics. During Phase 1 an initial translation of the existing criteria document was performed in addition to identifying and eliminating language within the criteria that duplicated existing NERC Reliability Standards.

Also during Phase 1, Functional Model language was introduced and the corresponding "B" Guidelines and "C" Procedures were incorporated into each Directory as Appendices. The resulting Directory created a single source reference for all entities while providing a method to demonstrate consistency with NERC Standards.

Phase 2 of the Directory Project was initiated in order to reformat the Criteria section of each document into specific and measurable NERC style requirements which will promote the NPCC regional criteria as more specific or more stringent within each Directory. Phase 2 will also facilitate the development of the NPCC Criteria Compliance Enforcement Program (CCEP) by providing the respective requirements of that program.

A mapping document has been provided on the Directory page of the NPCC Website and has been organized in a manner that provides guidance on where a Directory's content originated ("A"- Criteria, "B"- Guideline, or "C"- Procedure). The mapping document provides tracking of specific content language from documents that were translated or replaced by Directories and their Appendices. A link to the Directory Flowchart and the Directory Mapping documents is provided in the References section of this manual.

Most of NPCC's "B" Guideline and "C" Procedure documents were transferred to Directories as Appendices in support of the relevant criteria. Those B and C documents that were not incorporated into a Directory remain as standalone documents.

III. APPLICABILITY OF NPCC CRITERIA

The requirements of an NPCC Directory apply only to those facilities defined as NPCC bulk power system elements as identified through the performance based methodology of NPCC Document A-10, "Classification of Bulk Power System Elements," the current list of which is maintained by the NPCC Task Force on System Studies and approved by the NPCC Reliability Coordinating Committee.

Requirements to abide by an NPCC Directory may also reside in NPCC Member tariff requirements, bilateral contracts and other agreements between facility owners and/or operators and their assigned Reliability Coordinator, Planning Coordinator, Transmission Operator, Balancing Authority and/or Transmission Owner as applicable and may be enforceable through those external tariff requirements, bilateral contracts and other agreements.

IV. TASK FORCE ROLES AND RESPONSIBILITIES

With the development of the Directories it has been recognized that in certain cases more than one Task Force is responsible for the content of a Directory and coordination between Task Forces is necessary. In general, revisions and clarifications to a Directory shall be coordinated by the Lead Task Force of the document. Revisions to a Directory can be initiated in a fully bi-directional manner; that is either by the Lead Task Force responsible for the document or by another Task Force who is responsible for some portion (criteria or appendices) of the document.

This process will allow each Directory to remain under the control of the respective Lead Task Force which has the necessary expertise to keep each document current and accurate while also providing a means to coordinate component review of those segments of the Directory that may be under the control of another Task Force.

The Lead Task Force can initiate a full revision of the Directory in accordance with the NPCC Reliability Assessment Program (NRAP) date of approval or some need to revise the criteria section of the document. A link to the NRAP documents is provided in the References section of this manual.

The Lead Task Force will also notify other Task Forces under whose jurisdiction either a portion of the criteria or Appendices exists in order to coordinate the total document review and revision. Similarly, a Task Force which is not the Lead Task Force of the Directory, but is responsible for some portion of the document, shall coordinate a necessary revision to their section of the document through the Lead Task Force of the Directory.

V. DIRECTORY DEVELOPMENT AND REVISION PROCEDURE

1. NEW DIRECTORY

Any NPCC Full Member may request the development of a new Directory. The request shall be made to the NPCC Manager of Reliability Criteria via email and shall contain the background and justification for the development of the new Directory.

The NPCC Manager of Reliability Criteria shall forward the request for the development of a new Directory, along with a request for the RSC to authorize a Cost Effectiveness Analysis utilizing the NPCC CEAP procedure to the Regional Standards Committee (RSC). The RSC will review the request and assign the request to develop a new Directory to the appropriate Task Force. The Lead Task Force responsible for developing the new Directory shall draft an initial version of the document consistent with the Directory template in Attachment A.

The RSC working with NPCC Staff shall utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory via the Cost Benefit Analysis (CBA) section of the CEAP. After the RSC reviews and approves the CBA the Lead Task Force shall post the draft Directory to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process period, the Lead Task Force will discuss the comments submitted. The Lead Task Force shall also determine if the Cost Effectiveness Analysis (CEA) portion of the CEAP shall begin and where appropriate, request the RSC to initiate the CEA

If the responses to comments received on the draft result in substantive changes to the document, the revised draft shall be reposted to the Open Process for a successive 45 day posting period. The process of comment review, revision and re-posting for comment continues until no substantive modifications to the draft Directory are made.

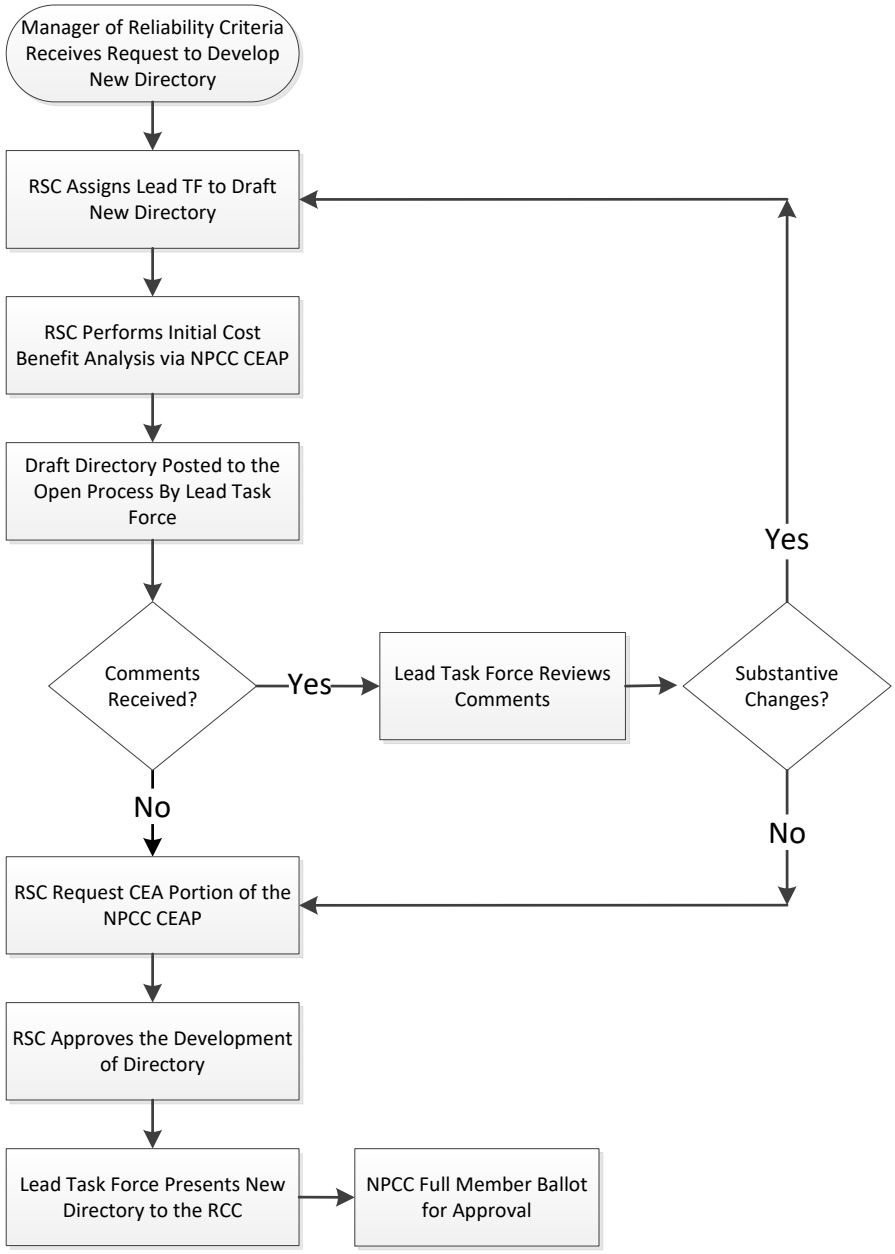
The RSC in accordance with the CEAP will use the responses to the CEA survey to develop a recommendation based on the cost effectiveness of the proposed Directory. After the RCC approves both the draft Directory and the CEAP the draft Directory is submitted for ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.[1]

---

[1] Approval of a new or revised Directory requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for establishing a new Directory is represented below in Figure 1:

Figure 1: New Directory



2. DIRECTORY REVISIONS

a. REVISIONS TO THE CRITERIA SECTION OF A DIRECTORY

Any NPCC Full Member may request a revision to the criteria within a Directory. A request to revise the criteria section of an NPCC Directory shall be submitted to the Lead Task Force responsible for the document. The Lead Task Force shall notify each affected NPCC Task Force which has jurisdiction over either a portion of the criteria or one or more of the appendices within the Directory that a request to revise the criteria in the document has been received.

In general, it is not anticipated that revisions to the criteria section of a Directory will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed Directory revision via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA for the proposed revision with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the revision process.

The Lead Task Force shall review the request to revise the criteria and shall also consider conforming changes to appendices as a result of the criteria revision if necessary. The NPCC Manager of Reliability Criteria shall post the Directory containing the revised criteria to the NPCC Open Process review for 45 days.

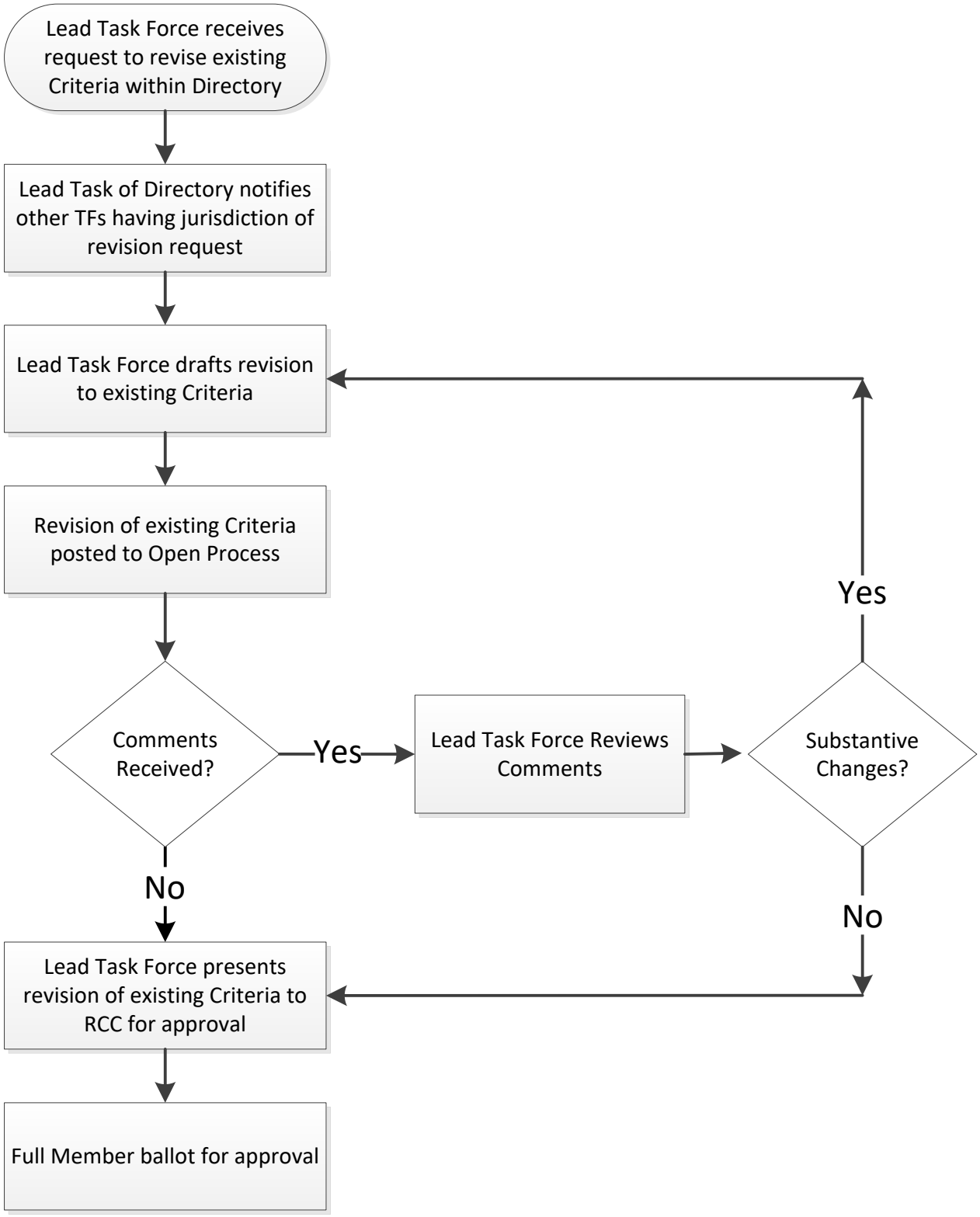
At the conclusion of the 45-day Open Process, the Lead Task Force will discuss the comments submitted and post responses to comments on the NPCC Open Process portal. If the responses to the comments received on the criteria revision result in substantive changes to the document, then the revised Directory criteria shall be reposted to the Open Process for a successive 45 day posting period.

Alternatively, if there are no substantive changes which would require additional postings, the Directory is presented to the Reliability Coordinating Council (RCC) for approval. Upon RCC approval the document is submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation of approval.

Approval of the revised Directory criteria requires a 2/3rd majority of Full Member voting representatives in accordance with the NPCC Bylaws.

The process for revisions to the criteria in an existing Directory is represented below in Figure 2:

Figure 2: Revisions to Criteria



b. REVISIONS TO THE APPENDIX SECTION OF A DIRECTORY

Any NPCC Full Member may request an Appendix within a Directory to be revised or retired. Revisions or retirements of Appendices shall only require Task Force approval.

A request to revise or retire an Appendix of a NPCC Directory shall be submitted to the Task Force responsible for the Appendix. The Task Force responsible for the Appendix shall notify the Lead Task Force of the Directory that a request to revise or retire an appendix within the document has been received.

The Lead Task Force of the Directory shall be responsible for notifying all Task Forces which have jurisdiction over either the criteria or one or more of the other Appendices within the Directory that a request to revise or retire an appendix has been received.

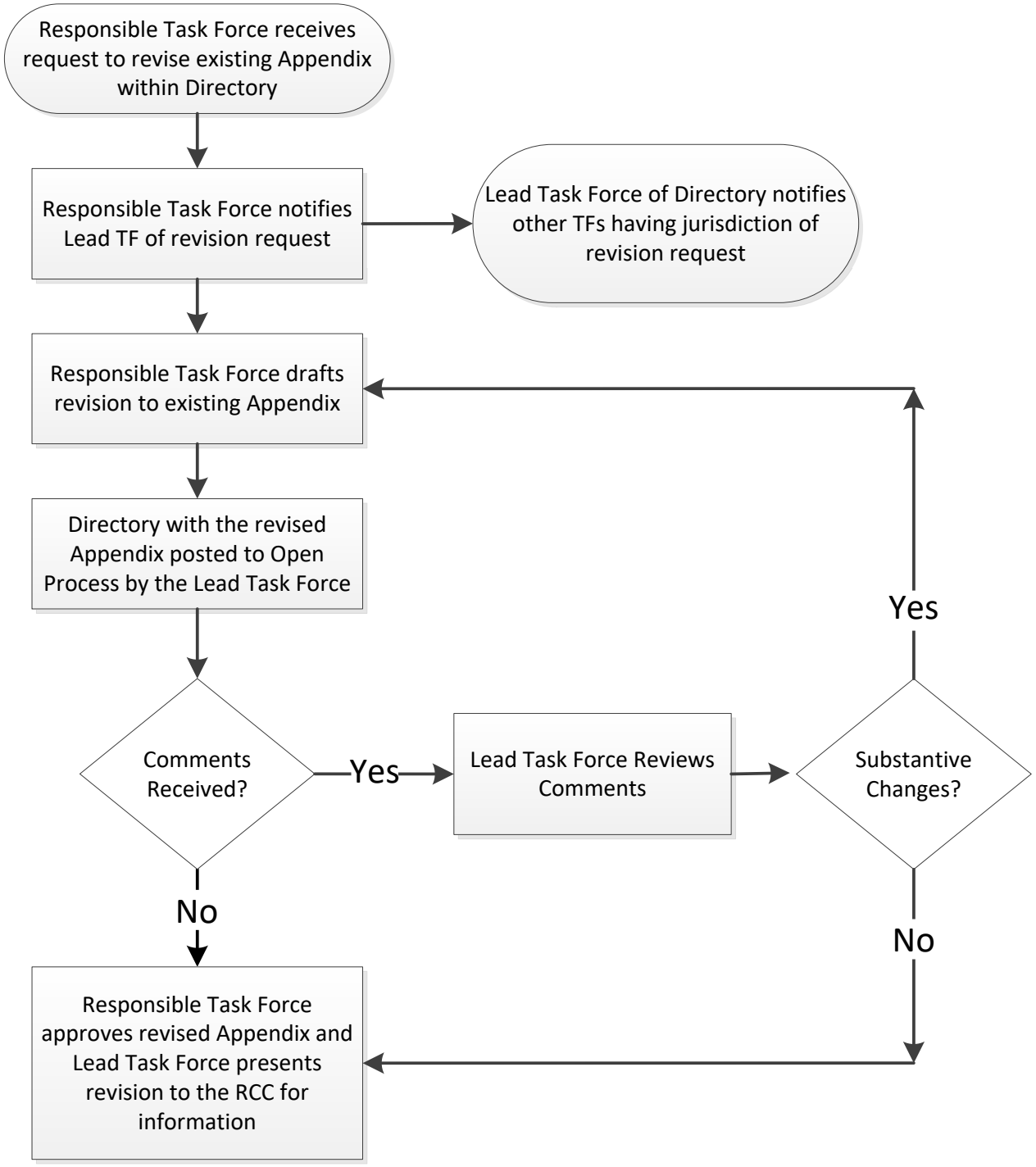
After the Task Force responsible for the revised Appendix request reviews the subject Appendix they will forward the Directory containing the draft revised Appendix to the Lead Task Force of the Directory. The Lead Task Force shall be responsible for posting the Directory (in its entirety) which contains the revised or retired Appendix to the NPCC Open Process review for 45 days. The Lead Task Force will limit the comments solicited to only the subject Appendix.

At the conclusion of the 45-day Open Process, the Lead Task Force will forward the comments submitted on the Appendix to the Task Force responsible for the revised or retired Appendix. If the responses to the comments received on the revised or retired Appendix result in substantive changes to the Appendix, then the Directory containing the revised or retired Appendix shall be reposted to the Open Process for a successive 45-day review period by the Lead Task Force of the entire Directory. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired Appendix shall be voted on by the Task Force responsible for the Appendix.

The lead Task Force for the Directory containing the revised or retired Appendix shall distribute the Directory containing the revised or retired Appendix to the Reliability Coordinating committee for informational purposes.

The process for revisions to the Appendices within an existing Directory is represented below in Figure 3:

Figure 3: Revisions to Appendices



c. REVISIONS TO THE NPCC GLOSSARY OF TERMS

The NPCC Glossary of Terms contains the definitions of all terms found within the NPCC Directories, Criteria, Guidelines, and Procedures and which are not already defined in the NERC Glossary of Terms or are regionally specific. The Glossary of Terms is intended to be a repository of all NPCC defined terms and contains the Full Member approved definition of that term as developed by the Task Force responsible for the Directory in which the term resides.

The Glossary is organized into two sections, one containing all defined terms within the Directories (including Appendices) which support the NPCC Criteria and another section for definitions found within remaining B and C documents.

The process of establishing or revising a NPCC defined term shall be considered a revision to the Directory in which the term resides in order to capture the context of its use within the document. Accordingly, the entire Glossary is not subject to the Open Process for a revision to an individual definition.

The development and review of a new definition or a revision to an existing NPCC specific definition contained within the Glossary will be coordinated by the Lead Task Force for the Directory in which the defined term resides.

Any NPCC Full Member may request that a Glossary term be revised or added to the NPCC Glossary of Terms by forwarding a request to the Lead Task Force for the Directory in which the defined term to be revised resides or will reside. When the subject term resides in multiple Directories, the requestor shall forward the request to each of the Task Forces for the Directories in which the defined term resides and the individual Task Forces shall coordinate their review of the request, by assigning one of the Task Forces as the Lead Task Force for the review.

In general, it is not anticipated that the development of a new or revised term in the Glossary will result in significant cost implications. However, the NPCC Manager of Reliability Criteria may request the RSC to utilize the NPCC CEAP to perform an initial analysis of the cost benefit of the proposed or revised Glossary term via the Cost Benefit Analysis (CBA) section of the CEAP.

The RSC will review the results of the CBA review of the proposed or revised Glossary term with the Lead Task Force and the NPCC Manager of Reliability Criteria prior to the Task Force proceeding with the process of establishing a new or revised Glossary term.

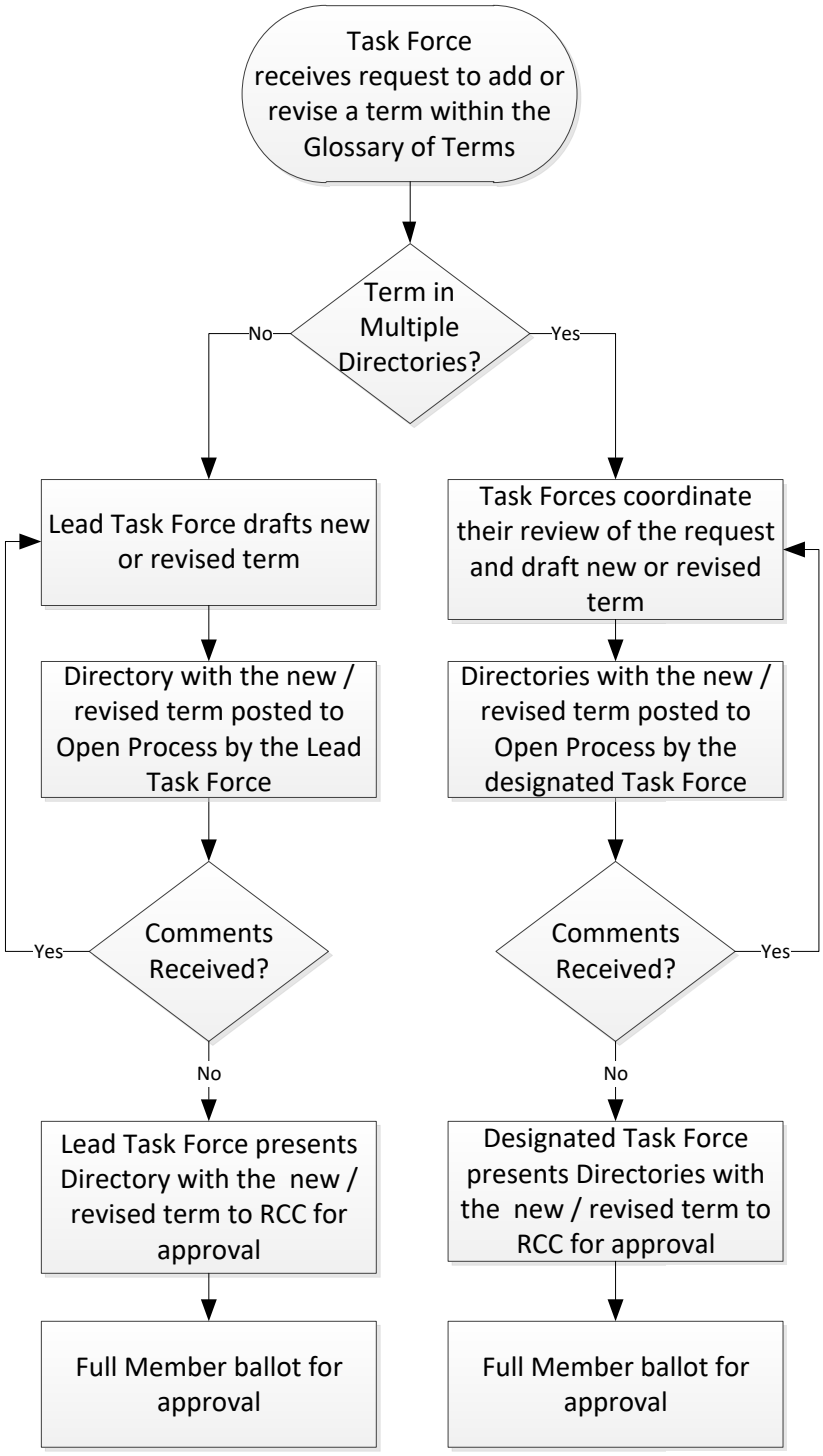
After the Lead Task Force in which the defined term resides has completed its review they will post the subject Directory containing the new or revised term to the NPCC Open Process for 45 days. When the new or revised term appears in multiple Directories, the designated Lead Task Force for the review shall include in the posting notice a comprehensive list of references to all occurrences of the defined term in other NPCC Directories, including each Directory in which the term resides.

At the conclusion of the 45-day Open Process, if responses to comments received on the new or revised term result in further substantive change to the term, then the Directory containing the new or revised term shall be reposted to the Open Process for a successive 45 day posting period by the Lead Task Force for the subject Directory. Alternatively, if no substantive changes to the term are developed which would require an additional posting, then the Directory containing the new or revised term will be presented to the Reliability Coordinating Council (RCC) by the Lead Task Force for approval.

Upon RCC approval the Directory containing the new or revised term will be balloted by the Full Members. Upon Full Member approval of the new or revised term the Glossary will be updated by the Lead Task Force of the document in which the term resides.

The process for revisions to the Glossary of Terms is represented below in Figure 4:

Figure 4: Revisions to the NPCC Glossary of Terms



d. WITHDRAWAL OF REVISION REQUESTS

Any NPCC Full Member which has initiated a request to develop a new Directory, revise an existing Directory or revise an NPCC Glossary Term may withdraw the request by notifying the NPCC Manager of Reliability Criteria.

3. DIRECTORY RETIREMENT

Upon identification of the need to retire an existing Directory, the Lead Task Force responsible for the Directory shall notify the NPCC Manager of Reliability Criteria of its proposal to retire a Directory.

The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. The NPCC Manager of Reliability Criteria shall post the proposal, along with supporting documentation to the NPCC Open Process for 45 days.

At the conclusion of the 45-day Open Process, the Lead Task Force will review the comments submitted and post responses on the NPCC Open Process portal. The NPCC Manager of Reliability Criteria shall present the proposal to retire the Directory to the Reliability Coordinating Council (RCC) for approval.

Upon RCC approval the proposal to retire the Directory will be submitted for a ballot to the NPCC Full Member Representatives along with the RCC recommendation to retire the document.

4. MAINTENANCE OF LINKS AND ERRATA

The maintenance of Links and the correction of errors found in a Directory or its Appendices shall be the responsibility of NPCC Standards staff. An error may be classified as Errata provided its correction does not change the scope or intent of the Directory and has no impact on the end user of the Directory.

Errata and Link revisions are updated as needed and require only the Lead Task Force approval prior to publishing and notifications to the applicable regulatory jurisdictions if required.

NPCC staff will also maintain a record of the change on the Directory Revision History page within the document.

VI. DIRECTORY CLARIFICATION PROCESS

a. REQUEST FOR CRITERIA CLARIFICATION

Any NPCC Full Member may request a clarification of the criteria within a Directory. The NPCC Full Member seeking the clarification shall submit a ***Request for Criteria Clarification*** form [2] to the NPCC Manager of Reliability Criteria explaining the clarification required and the specific circumstances surrounding the request. The NPCC Manager of Reliability Criteria shall review the request and work with the originator to make certain that the request is clearly written, seeks clarity regarding the intent or purpose of the criteria and is not a question on a compliance aspect of the criteria.

The Manager of Reliability Criteria will forward an approved *Request for Criteria Clarification* to the NPCC Task Force designated as the Lead Task Force for the subject Directory. The Lead Task Force shall notify each NPCC Task Force which has jurisdiction over either another portion of the criteria and /or one or more of the appendices within the subject Directory, that a ***Request for Criteria Clarification*** has been received. The Lead Task Force shall also forward the request to the affected Task Force.

The Lead Task Force for the Directory or the Task Force having jurisdiction shall review the request among its Members and provide a response to the NPCC Manager of Reliability Criteria within 60 calendar days. The Manager of Reliability Criteria shall post the ***Request for Criteria Clarification***, along with the responses provided by the Lead Task Force to the NPCC Open Process for 45 days.

The Lead Task Force will consider all comments received on the posted clarification and if necessary revise the clarification based on these comments. If the Lead Task Force revises the clarification substantively on the basis of comments received the clarification shall be reposted to the NPCC Open Process for a successive 45 day posting period.

The Manager of Reliability Criteria will coordinate a response to all commenters on behalf of the Lead Task Force. The Lead Task Force response to a Directory

[2] The Request for Clarification Form is included in Appendix B of this document.

clarification request shall provide the requested explanation without expanding on the criteria and should be sufficiently concise to eliminate any ambiguity.

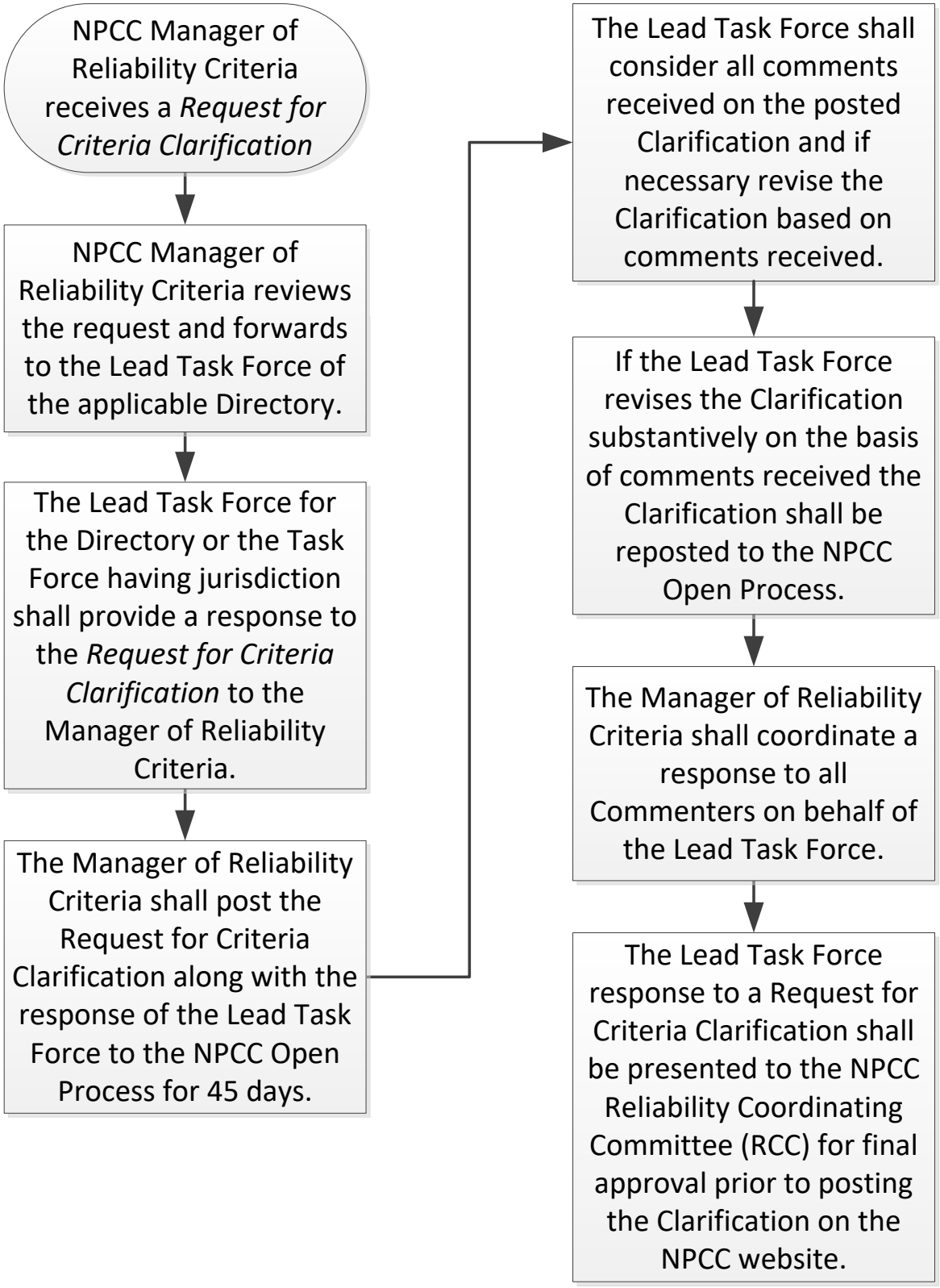
The NPCC Manager of Reliability Criteria shall review the clarification provided by the Lead Task Force or the Task Force having jurisdiction to ensure that it is clear and provides the requested explanation without expanding on the criteria.

The Lead Task Force response to a ***Request for Criteria Clarification*** shall be presented to the NPCC Reliability Coordinating Committee (RCC) for final approval prior to posting the clarification to the NPCC website.

The detailed results of the ***Request for Criteria Clarification*** shall be retained by the Lead Task Force and the NPCC Standards Staff along with a recommendation on whether the language within the document should be revised in order to provide additional clarity.

The process for a Criteria Clarification Request is represented below in Figure 5:

Figure 5: Request for Criteria Clarification



b. APPEALS

Any NPCC Full Member that has submitted a *Request for Clarification* may appeal the rendered Task Force response.

The appellant shall submit a written complaint to the NPCC Manager of Reliability Criteria describing the substantive or procedural action or inaction associated with the Clarification Request process.

The appellant shall also describe in the complaint the actual or potential adverse impact to the appellant.

Assisted by any necessary NPCC Standards Staff and Lead Task Force resources, the NPCC Manager of Reliability Criteria shall prepare a written response addressed to the appellant as soon as practical, but not more than forty-five (45) calendar days after receipt of the complaint.

VII. REVIEW AND APPROVAL OF THE NPCC DIRECTORY DEVELOPMENT AND REVISION MANUAL

The NPCC Directory Development and Revision Manual will be reviewed at least once every five (5) years or more frequently if required.

A notification of a pending RSC review and re-approval of the Manual shall be posted on the NPCC website. All revisions to this Manual shall be posted to the NPCC Open Process Review for 45 days.

The Regional Standards Committee (RSC) shall respond to all comments received and shall have final approval over the revised document.

VIII. DIRECTORY FORMAT AND VERSION CONTROL

Each Directory will be formatted in accordance with the Directory Template in Appendix A of this document.

The Task Force Revision Review Record on the cover page of each Directory shall contain the date of the most recent version of the Directory as approved by the Full Members of NPCC.

The Revision History record on page 2 of each Directory shall contain a record of all revisions to the document, including maintenance of errata and links.

IX. PROCESS FOR REVIEW AND APPROVAL OF CRITERIA, GUIDES, AND PROCEDURES

Introduction

The Process for Review and Approval of Criteria, Guidelines, and Procedures was formerly outlined in NPCC Document A-01 *Criteria for Review and Approval of Documents.* The Directory Project has consolidated most NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents into the Directories.

This section is intended to outline the review and approval procedures, (the NPCC Open Process), to be followed for all remaining NPCC Criteria-Type "A" documents, Guideline-Type "B" documents, and Procedure-Type "C" documents.

Document, Criteria - Type "A"

General Description

Type "A" documents, with approval by the NPCC Full Member Representatives; describe the minimum criteria for Member Systems of NPCC functioning as part of the coordinated interconnected network.

Review and Approval

Type "A" documents are prepared and revised by the designated lead Task Force on a periodicity to be determined by the lead Task Force or initiated at the request of a Full Member. Drafts are distributed to other Task Forces for review, comments and/or concurrence. The document is also posted on the NPCC Open Process webpage for review for a period of 45 days, allowing industry comment. Notification is also given to neighboring Regions whose reliability might be impacted by NPCC's Criteria. Their review of the proposed Criteria will be encouraged and comments will be considered for inclusion. The lead Task Force will discuss the comments submitted and post the responses to those comments on the NPCC Open Process webpage. If no substantive changes are required, which would require additional posting(s), the draft Type "A" document is presented by the lead Task Force to the Reliability Coordinating Committee (RCC) for its approval.

In its review, the RCC will determine if the proposed or revised Criteria are neither inconsistent with nor less stringent than NERC industry-wide reliability standards and are not intended to result in any undue competitive advantage or disadvantage to any party or parties. The NPCC recognizes that Member systems or local conditions may require criteria which are more stringent than those defined by NPCC Criteria.

Should the RCC determine that the document cannot be approved, the RCC will return the document to the lead Task Force.

Following the RCC's approval, the document is submitted to the NPCC Full Member Representatives for ballot, with a recommendation for its adoption. Approval of NPCC Criteria requires a 2/3rd affirmative majority of the weighted sector votes. See Appendix C for further details on the entire NPCC Open Process.

For modified Type "A" documents, once approval has been obtained from the Member Representatives, the document is officially adopted with an effective date or implementation plan, as noted on the document itself with the following statement:

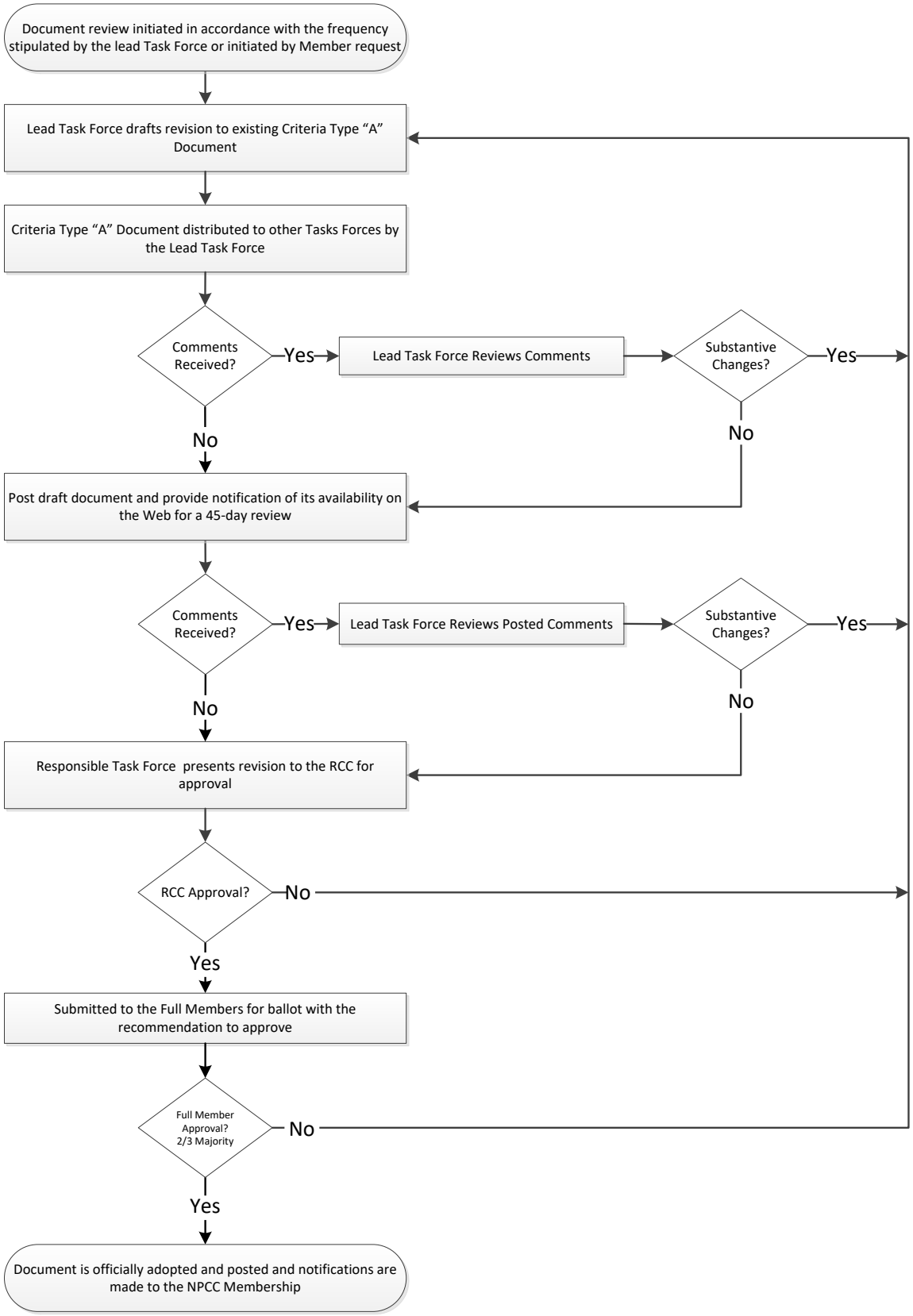
"Adopted by the Members of the Northeast Power Coordinating Council Inc., on (mm, dd, yyyy) based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Inc. Bylaws dated January 1, 2012 as amended to date."

The approved and adopted Type "A" document will then be posted, along with necessary additional documentation, if needed, such as an implementation plan or schedule for achieving full compliance with the requirements outlined in the document. This will be posted on the NPCC web site and distributed to the membership via a documented and maintained distribution list
Members may request the lead Task Force, at any time, to review and revise the Criteria, or portions thereof, and have the right to enter into the NPCC "Appeals and Dispute Resolution Process" for non-compliance issues.

Retiring a Type "A" document requires following the same steps as the revision process.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 6:

Figure 6: Revisions to Document, Criteria - Type "A"



Documents: Guideline - Type "B" and Procedure-Type “C”

General Description

Type "B" documents are guideline documents.

Type "C" documents are procedures which provide for consistent implementation, interpretation and monitoring of conformance with the general criteria, guides and reporting requirements.

Review and Approval

Any NPCC Full Member may request a Guideline-Type “B” or a Procedure-Type “C” document be revised or retired. Revisions or retirements of Guideline-Type “B” or Procedure-Type “C” documents shall only require Task Force approval.

A request to revise or retire a Guideline-Type “B” or a Procedure-Type “C” document shall be submitted to the Task Force responsible for the document.

The Task Force shall be responsible for posting the revised or retired document to the NPCC Open Process review for 45 days.

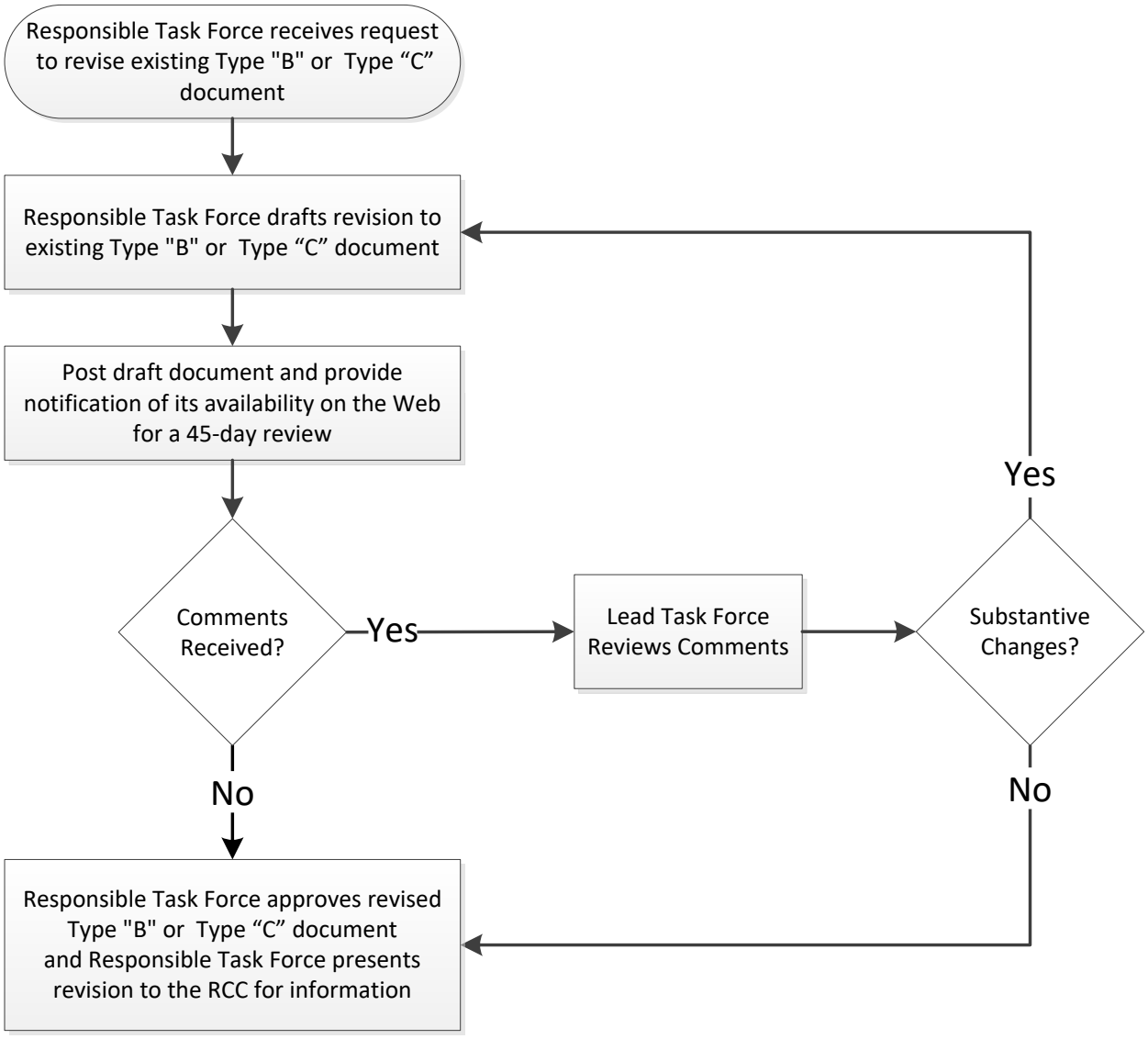
The revised B or C document (or the proposal to retire a B or C document) shall be posted to the NPCC Open Process for a 45-day posting.

At the conclusion of the Open Process, the Task Force responsible for the B or C document shall consider all comments received and incorporate comments as appropriate. If the comments received on the revised or retired document result in substantive changes to the document, then the document shall be reposted to the Open Process for a successive 45-day review period by the Task Force responsible for the document. Alternatively, if there are no substantive changes which would require additional postings, the revised or retired document shall be voted on by the Task Force responsible for the document.

The Task Force responsible for the document shall distribute the document to the Reliability Coordinating committee for informational purposes.

The process for revisions to the criteria in an existing Type "A" document is represented below in Figure 7:

Figure 7: Revisions to Guideline - Type "B" and Procedure-Type “C” Documents



APPENDIX A - DIRECTORY FORMAT TEMPLATE

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

NPCC
Regional Reliability Reference Directory # XX

Task Force XXXXX Revision Review Record:
XX/XX, 20XX

Adopted by the Members of the Northeast Power Coordinating Council, Inc. June 26th, 2009 based on recommendation by the Reliability Coordinating Committee, in accordance with Section VIII of the NPCC Amended and Restated Bylaws dated July 24, 2007 as amended to date.

Revision History

Version	Date	Action	Change Tracking (New, Errata or Revisions)
0		**Effective Date**	**New**

Format for NPCC Directories (Phase 2)

Effective Dates (Denotes date of adoption by the Membership)

Revision History (Depicts revision history and tracks key changes)

Table of Content (Self-explanatory)

A. Introduction

Title: Self-explanatory

Directory #: Self-explanatory

Objective: State the reliability objective that this Directory intended to meet (i.e., achieving specific performance target/outcome, mitigating particular risks, establishing the minimum capability level, etc.)

Effective Date: Identify which parts of the Directory become effective on which dates.

Background: Provide information related to this creation or revision of this Directory, e.g., which "A", "B" or "C" documents are mapped into this Directory; the general basis of the Directory, etc.

Applicability: Identify the entities that are assigned reliability requirements and/or which facilities need to conform to the stipulated criteria.

B. NERC ERO Reliability Standard Requirements

A list of the NERC standards associated with this Directory.

C. NPCC Regional Reliability Standard Requirements

A list of NPCC Regional Standards associated with this Directory.

D. NPCC Full Member, More Stringent Requirements, Criteria and Measures

Requirements

List the requirements and criteria that the applicable entities or facilities must comply with.

E. Compliance

Compliance with the requirements set forth in this Directory will be in accordance with the NPCC Criteria Compliance and Enforcement Program (CCEP).

Measures and corresponding Levels of Non-Compliance for these requirements are contained within the compliance template associated with this Directory.

Prepared by:	Task Force XX (Lead Task Force for the Directory)
Review and Approval:	Revision to any portion of this Directory will in accordance with the NPCC Directory Development and Revision Manual and will be posted by the Lead Task Force in the NPCC Open Process for a 45-day review and comment period. Upon satisfactorily addressing all of the comments in this forum, the Directory will be sent to the RCC for its approval. Upon approval of the RCC, this Directory will be sent to the Full Member Representatives for their final approval if sections pertaining to the Requirements and Criteria portion have been revised. All voting and approvals will be conducted according to the most current "NPCC. Bylaws" in effect at the time the ballots are cast. Revisions pertaining to the Appendices or any other portion of the document such as links, glossary terms, etc., only RCC Members will need to conduct the final approval ballot of the document. This Directory will be updated at least once every three years and as often as necessary to keep it current and consistent with NERC, Regional Reliability Standards and other NPCC documents.

APPENDIX B – NPCC REQUEST FOR CLARIFICATION

NORTHEAST POWER COORDINATING COUNCIL, INC.
1040 AVE OF THE AMERICAS, NEW YORK, NY 10018 TELEPHONE (212) 840-1070 FAX (212) 302-2782

NPCC Request for Criteria Clarification

Note: An Interpretation cannot be used to revise a Directory.

Request for Criteria Clarification of a Directory
Date clarification request submitted: Date clarification response provided:
Contact information for person requesting the clarification:
Name:
Organization:
Telephone:
E-mail:
Identify the Directory that needs clarification:
Directory Number:
Directory Title:
Identify specifically what portion of the Criteria needs clarification:
Text of Requirement:
Identify the material impact associated with this clarification:
Identify the material impact to your organization or others caused by the lack of clarity within this Directory:

Submit completed Request for Criteria Clarification forms to the NPCC Manager of Reliability Criteria.

Clarification: Response to Request for Clarification of Directory XX for the XXXX Corporation
The following clarification of Directory was developed by the Task Force on XXXXX
Directory Number and Text of Requirement
Question 1
Response to Question 1
Question 2
Response to Question 2

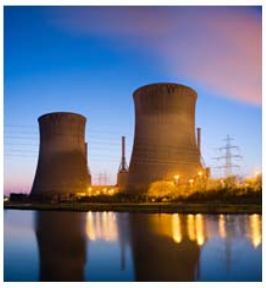
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

ERO Reliability Risk Priorities

RISC Recommendations to the NERC Board of Trustees

DRAFT October 2017

RELIABILITY | ACCOUNTABILITY



3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
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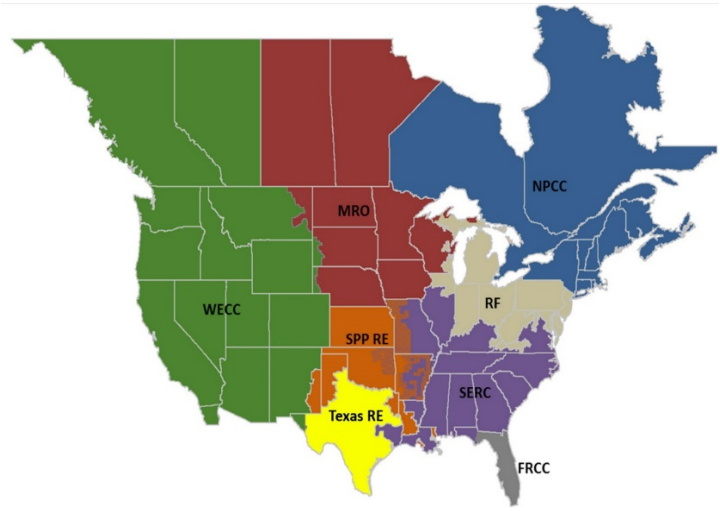
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

The Reliability Issues Steering Committee (RISC) is an advisory committee to the NERC Board of Trustees (Board). The RISC provides key insights, priorities, and high-level leadership for issues of strategic importance to BPS reliability. The RISC advises the Board, NERC standing committees, NERC staff, regulators, REs, and industry stakeholders to establish a common understanding of the scope, priority, and goals for the development of solutions to address emerging reliability issues. The RISC provides guidance to the ERO Enterprise and the industry to effectively focus resources on the critical issues to improve the reliability of the BPS.

This 2017 report presents the results of the RISC's continued work to strategically define and prioritize risks to the reliable operation of the BPS and thereby provide recommendations to the Board regarding the approach that NERC should take to enhance reliability and manage those risks.

Preamble

The RISC has identified a number of key observations regarding emerging risks to the reliability of the BPS to focus the industry's efforts. These key observations are:

1) the fast pace of change of the resource mix,
2) interdependence between the energy and communication sectors,
3) increased complexity of the power system automated control systems due to the increased use of power electronics and digital controls and the risks of negative interaction between those control systems,
4) ongoing evolution and complexity from determined actors using cyber technologies
5) changing workforce skills needed to reliably implement the new control facilities involved in the power system, and
6) addressing BPS impacts associated with emerging reliability risks is placing increased demands for coordination among policy makers and regulatory authorities, including the need for increased coordination among provincial, federal, and state regulatory authorities, with due consideration of jurisdictional boundaries.

These key observations were used to draw linkages and coordinate the recommendations across the ERO Reliability Risk Priorities Report's risk profiles. By identifying risks, whether associated with the planning and operation of generation, transmission, or distribution[1] facilities, the RISC recognizes that not all of the recommendations are within the ERO's jurisdiction.

[1] Distribution facilities are not within the BPS however there is expected to be a greater dependence on distribution systems for achieving reliable operation of the BPS as the transition to distributed resources continues.

Chapter 1: Background and Introduction

Background

This 2017 annual report documents the results of the RISC's continued work to identify key risks to the reliable operation of the BPS. This report proposes relative priorities and management effort pacing and provides input to the Board on recommended actions.

The RISC's obligations are based on the Board's resolutions on the initial 2013 RISC recommendations[2]:

> *RESOLVED, that the Board hereby accepts the report of the Reliability Issues Steering Committee (RISC), expresses its appreciation to the RISC for the excellent report, and endorses continued work by the RISC on a gap analysis on the high-priority and then the medium-priority issues and requests continued reports to the Board.*
>
> *FURTHER RESOLVED, that the Board hereby directs NERC management to continue to work with the RISC to consider how the priority rankings should be reflected in the development of the ERO's business plan and in the work plans of NERC committees.*
>
> *FURTHER RESOLVED, the Board hereby directs NERC management to work with the RISC and, as appropriate, NERC committee leadership to consider how NERC should utilize a data-driven reliability strategy development process that integrates with budget development and overall ERO planning (e.g., Standing Committee planning, department, and employee goal-setting).*

There are important links between the risk priorities and the recommended actions for the ERO Enterprise and industry. While the individual risk profile recommendations in this report are presented independently, there are interdependencies between many of the risks that present unique challenges to the electricity industry. The RISC acknowledges and appreciates the increased reliance of the Board and ERO Enterprise leadership on this report as an input for the ERO Enterprise's Long-term Strategic Plan, Operating Plan, and Business Plan and Budget.

The RISC participants include representatives from the NERC standing committees, the Member Representatives Committee (MRC), and "at large" industry executives. The observations, findings, and guidance presented in this report include input from industry forums, trade associations, and other industry groups. The RISC also received feedback through stakeholder comment periods and during open MRC meetings.

The 2017 report relies on and extends the comprehensive initial assessment and corresponding recommendations to the Board made in February 2013, which have been updated and refined annually. This report and recommendations reflect discussions with representatives from the NERC technical and standards committees, industry dialogue through a series of focused executive leadership interviews, the discussion with leaders at the NERC Reliability Leadership Summit, the FERC Reliability Technical Conference, and many technical reports and assessments. These results were presented to ERO Enterprise executive leadership for integration into the ERO Enterprise strategic and operational plans.

[2] *See* minutes from the Board's February 7, 2013, meeting: http://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/BOT%20-%20February%207%202013%20Minutes.pdf

Introduction

The RISC has carefully reviewed numerous inputs on BPS reliability from various stakeholders. This report reflects the collective opinion of the RISC regarding the priorities. The RISC reviewed and assembled information from ERO Enterprise[3] stakeholders, policy makers,[4] and focused executive leadership interviews to develop a composite set of risk profiles and a graphic depiction of the key risks to the system. The depiction presents the likelihood of occurrence, the expected impact on reliability, and the trajectory of the associated risks.

The individual risk profiles have been categorized as High, Moderate, or Lower.

- High risks are emerging risks that are not generally understood by industry, regulators and policy makers. The reliability risks are known to exist, but more recently identified and the extent of the risk and impacts not clearly understood. More analysis and experience is required to further define the risks and to develop mitigating actions.
- Moderate risks are evolving risks with impacts that are somewhat understood by industry, regulators and policy makers. The reliability risks have been identified but have attributes that are different from risks dealt with by the industry in the past. New or additional mitigating actions or methods need to be developed and implemented.
- Lower risks do not mean that possible reliability impact is small, but rather the profiles are known or existing risks that are universally understood and have been accepted by regulators and policy makers. The reliability risks have been identified, analyzed and should continue to be mitigated by known methods and approaches. The risks are predictable, well defined, and at least similar to reliability issues that have been dealt with by the industry in the past.

Thus, even risks that are well understood and have measures in place for risk mitigation are included as risk profiles because the industry must remain vigilant in addressing these Lower or Moderate risks in order to prevent the profiles from being escalated higher.

All of the identified risks are important and a Moderate or Lower ranking does not indicate that the risk as described in its profile is not a threat to reliable operation of the system. These risks still require monitoring and action to mitigate or reduce the likelihood of instability, uncontrolled separation, or cascading outages that adversely impact the reliability of the BPS. Regardless of the ranking or classification, all risk profiles warrant attention as the rapidly changing BPS can quickly raise the risk. Accordingly, the risk profiles were categorized as follows:

High Risk Profiles

- Cybersecurity Vulnerabilities
- Changing Resource Mix
- BPS Planning
- Resource Adequacy

Moderate Risk Profiles

- Increasing Complexity in Protection and Control Systems

[3] ERO Enterprise is interpreted to mean NERC, the Regional Entities, and the technical committees of NERC.

[4] Policy makers is used generally to mean any organization that can impact the legal or regulatory framework in place at various levels, including local, state, federal, and provincial governmental authorities in addition to various trades and lobbying organizations.

- Loss of Situational Awareness
- Physical Security Vulnerabilities
- Extreme Natural Events

Lower Risk Profiles

- Human Performance and Skilled Workforce

Format of the Report and Method of Analysis

The primary objective of this report is to highlight risks that merit a continued level of attention and recommended actions that align with the multidimensional aspects of the risk. This report differs from other ERO reports, such as the annual *State of Reliability,* in that it is a forward-looking view of the BPS. The *State of Reliability* reviews data from previous years to draw objective conclusions.

A majority of this report is comprised of risk profiles that detail the evolving status and mitigation efforts to address each specific risk. These profiles outline a summary of the risks and the potential impact to the BPS. Through the profiles, the RISC recommends activities to manage the risks in the near-term, mid-term, and long-term. The ERO Enterprise and industry can use the composite risk profiles and the risk map for baseline and recurring evaluation of reliability risks.

Where appropriate, the RISC identified the group or entity that should take mitigating action; however, some recommendations do not present a clear owner or responsible party. In these cases, the recommendation is presented as a more generalized action item that can apply to numerous entities, including policy makers, industry, and the various organizations within the ERO Enterprise.

Additionally, the committee evaluated risks based on impact to the BPS regardless of the source or location of the risk. To evaluate key risks to the system, the committee recognized emerging issues emanating from different areas of the grid. For example, resources such as distributed energy resources which may not be located or directly connected to the BPS. Operators and planners of the BPS are aware of the need to have a wide-area view of changes to the system to provide an understanding of external conditions that can affect them; therefore, the profiles note several risks where the BPS can be impacted at interfaces (*e.g.,* distributed resources, resources located on the distribution system, gas delivery, telecom, water, etc.). RISC determined it is important to shine a light on external factors that increase BPS risk and offered recommendations to address them. Given the changing nature of the system and acceleration of integrating distributed energy resources especially on the distribution system, the RISC is obligated to raise areas of concern since impacts from distributed resources may require mitigation actions at the BPS level.

Other inputs to the Risk Profiles

Reliability Leadership Summit

On March 21, 2017, NERC and the RISC hosted a Reliability Leadership Summit (Summit) with leaders of the reliability community, including top industry executives, state and federal regulators, and NERC and Regional Entity senior leadership. The Summit included moderated panels focused on identifying and discussing challenges around three main topics: (1) challenges in operating the BPS; (2) resiliency and security; and (3) emerging risks to reliability. Common themes and takeaways from the Summit included the following:

- The RISC report accepted by NERC's Board in 2016 does not appear to have any gaps in identified risks, though their pace has accelerated.

- Risks related to Distributed Energy Resources (DER) was a prominent theme during the Summit, including the influence of digital-based systems, lack of situational awareness, planning methods and forecasting models, overlapping regulatory responsibilities and inconsistent policies, and jurisdictional limitations. The work and recommendations of the DER Task Force should be reviewed and leveraged accordingly.
- DER and changing technologies imply large amounts of new data, resulting in data management burdens and its protection as a risk. Despite the risks related to data protection, there are also risks related to not sharing data for situational awareness and learning purposes.
- Cybersecurity threats continue to evolve and escalate, posing an increasing level of threat to the BPS.
- The RISC report should recognize the international aspect of policymaking.
- The "skilled workforce" risk profile may be more appropriately titled "changing workforce." The skills required are evolving, including responsibilities related to compliance.
- Risk mitigation mechanisms for smaller utilities need to be explored.
- Gas dependency and other common mode failure events involving telecommunications and water related systems continue to be prominent risks.
- Addressing BPS impacts associated with emerging reliability risks is placing increased demands for coordination among policy makers and regulatory authorities, including the need for increased coordination among provincial, federal, and state regulatory authorities, with due consideration of jurisdictional boundaries.

FERC Technical Conference

On June 22, 2017, FERC conducted a commissioner-led technical conference on reliability. The purpose of the conference was to discuss policy issues related to the reliability of the BPS. As part of its review of emerging risks to the reliable operation of the BPS, RISC used the inputs and active discussions at this conference to supplement its development of the risk profiles. The technical conference addressed four main topics: Overview of the State of Reliability, International Perspectives, Potential for Long-Term and Large-Scale Disruptions, and Grid Security. These topics were addressed in four panel sessions:

- The first panel focused on an **Overview of the State of Reliability.** The participants of this panel affirmed several of the risks identified by the RISC. The panelists identified the most significant risks to the BPS as impacts from integrating distributed energy resources, retirement of base-load resources, jurisdictional gap between Federal and state/provincial regulations, cyber-system supply chain risks, increased variable energy resources, resource adequacy, and risks from the accelerated pace of technology integration such as smart inverters having unintended consequences. This panel also highlighted the need for review of NERC's standards to ensure they are effective, and eliminate those requirements which are not addressing important risks to BPS reliability.
- The second panel focused on **International Perspectives** from Canada, Mexico, and the European Union on the grid's emerging issues, including the changing resource mix, introducing and expanding markets, improving transmissions planning across international borders, and expanding pipeline infrastructure to facilitate additional gas-fired generation.
- The third panel focused on the **Potential for Long-Term and Large-Scale Disruptions**, which continued the first panel's discussion on emerging trends and risks, but concentrated on the impact of the reliance on a single gas storage facility, electromagnetic pulse, and resiliency of the grid.

- The final panel, addressing **Grid Security,** highlighted controls to mitigate cybersecurity risks to the BPS, particularly in light of the 2015 and 2016 cyber-attacks on the electric grid in Ukraine. In addition, the need to develop a culture of cyber-awareness among the workforce was identified.

Pulse Point Interviews

In order to expand the consideration of potential reliability risks from a strategic perspective, the RISC conducted one-on-one interviews with key industry executives and leaders to gain their insight. The goal was to focus on important reliability risks from different vantage points among regulators and utilities and to ensure that key areas of reliability concern and relevant priorities were adequately identified for consideration by the RISC.

Challenges discussed during the pulse point interviews were generally focused on four areas: changing resource and technology, economic considerations, cyber and physical security, and regulatory.

Several interviews validated the concerns presented in the risk profiles. The profiles of Changing Resource Mix and Cybersecurity Vulnerabilities were the most common themes in all of the interviews. In addition, several industry executives voiced concerns over lack of fuel diversity and the greater reliance on natural gas. Many utilities commented that natural gas currently serves as the baseload fuel for their areas, heightening the need for greater focus on gas infrastructure in order to identify potential risks to the BPS. Further, interviewees discussed resilience and a concern about how changes to the grid are reducing resilience. A few interviewees encouraged the ERO to place a stronger emphasis on the electro-magnetic pulse (EMP) threat, particularly with high altitude devices capable of causing widespread outages. Also one leader suggested changing the focus to constructing a more resilient distribution system to support reliability as more renewables and other resources are being added to the distribution system.

Although several interviewees acknowledged that NERC has no jurisdiction over markets, there is a growing concern that the existing markets do not accurately reflect products necessary to support the new resources being integrated today. For example, several markets may not include ancillary services necessary to support reliability when relying on more distributed resources.

A continued theme from 2016 is some interviewees are concerned about a workforce shortage, such as protection and control engineers. The aging workforce has been a consistent theme throughout the years, and some leaders provided support for continuing to monitor this risk.

Several executives expressed concern about whether regulators and policy makers would support the cost recovery needed to address these challenges to maintain system performance and the reliable operation of the power system.

Department of Energy Grid Study

In August 2017, the Department of Energy (DOE) published a study, "*Staff Report to the Secretary on Electricity Markets and Reliability,*"[5] aimed at evaluating the present status of the electricity system and exercising foresight to help ensure a system that is reliable, resilient, and affordable long into the future. The study includes four key chapters (Power Plan Retirements, Reliability and Resilience, Wholesale Electricity Markets, and Affordability) and eight policy recommendations. These recommendations are related to reliability and resilience, as well as wholesale markets. This is confirmation of the direction the RISC is advocating.

[5] https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf

Focus Areas and Recommendations from the Risk Profiles

Outlined here are the highest priority focus areas identified in the 2017 risk profiles. Concentrated effort by the industry on these areas, as well as inclusion of goals within the ERO Enterprise Operating Plan and the associated Business Plan and Budget, should improve BPS reliability. Additional detail can be found in the associated risk profiles.

Cybersecurity Vulnerabilities (Risk Profile #9)

- The ERO Enterprise and the industry should adopt a nimble, multipronged approach to address the continually evolving cybersecurity threat. Examples of nimble tools include increased Electricity information sharing and analysis centers (E-ISAC) participation and products, peer reviews and assistance visits to move to a best-practice model, and guides and recommendations for new and less-defined threats.
- The E-ISAC, the Telecommunications, and Natural Gas Information Sharing and Analysis Centers should enhance communications. Expand the use, availability, and value of cybersecurity threat and vulnerability information sharing, analytics, and analysis.
- The ERO Enterprise and all utilities should foster development of a security culture among their employees.

Changing Resource Mix (Risk Profile #1)

- The ERO Enterprise should:
  - Assess the risks associated with single points of disruption of natural gas as well as the uncertainty of supply.
  - Use special assessments and studies to inform and educate policy makers, regulators, and the industry of reliability effects and interconnection requirements.
  - Gather data and insights on distributed energy resources in an effort to improve visibility, predictability, and the dispatchability needed to support BPS reliability.
  - Continue to provide independent technical assessments on reliability issues stemming from proposed regulatory rules or statutes as well as any significant tariff rules related to the changing resource mix.
  - Further develop lessons learned based on operational experience with variable energy and distributed energy resources.
- To address the impact on ERS, NERC should benchmark and support technical studies on frequency and inertia response, voltage support, short-circuit analysis, and inter-area oscillations.

BPS Planning (Risk Profile #2)

- The ERO Enterprise should:
  - Coordinate with the industry, manufacturers and developers of asynchronous resources to develop and make available accurate dynamic models.
  - Identify the type and frequency of information needed from distributed energy resources.
  - Work with the industry and forums to create guidelines and good industry practices for developing and maintaining accurate system, dynamic and electromagnetic models that include transmission, resources, load, and controllable devices for use in long-term and operational planning.

- Continue to assess ERS performance to develop necessary guidelines and to determine if Reliability Standards are required.
- NERC should continue to collaborate with Planning Coordinators to expand development of interconnection-wide models commensurate with expected dispatches. This collaboration will support the ability to conduct more effective long-term planning assessments.

Resource Adequacy and Performance (Risk Profile #3)

- The ERO Enterprise should:
  - Continue to improve modeling and probabilistic methods with industry to evaluate resource adequacy to include impacts from ERS, unit retirements, and load and resource variability during different time frames (including shoulder months).
  - Assess and develop mitigation recommendations to address single points of disruption, such as fuel contingencies, that will result in large resource outages.
  - Continue to assess vulnerabilities of fuel availability as part of evaluating resource adequacy and operational capability.
- The industry should evaluate opportunities to develop more accurate short-term load forecast models.
- Analyze data requirements necessary to ensure there is sufficient detail on the capability and performance of the BPS as it is impacted by distributed energy resources. The industry should gather data beyond simple demand forecasts and expand to identify resource capacity, location, and ERS capability.

Themes and Takeaways from the Risk Profiles

In drafting the 2017 risk profiles, no new major risk profiles have been identified. However, several key themes from the profiles show where industry attention is needed.

Resilience and Recovery

Resilience and recovery actions can mitigate exposure from multiple risks. This is particularly important as threats to electric industry infrastructure from cyber and physical attacks are expected to increase, and customers and regulators have increasing expectations on the continuity of electric service. While this report addresses ways to address specific risks, not all possible risks can be anticipated or mitigated. Efforts and resources expended on resilience and recovery can address a wide range of risks and can also limit the extent of extreme or low-likelihood incidents. Resilience assessments in the planning and operating processes should be pursued to support BPS reliability.

Spare equipment strategy is an important aspect of restoration and recovery. It should encompass identifying critical spare equipment as part of a national or regional inventory. The strategy should also account for the transportation/logistics requirements for replacing critical assets. An improved spare equipment strategy or plan will lead to better planning and possibly faster response times for restoration and recovery.

Part of the RISC's role is to identify trends and evolving issues that have the potential to degrade reliability so that actions based on sound technical judgment can be taken. As the character and reliability behavior of the BPS evolves, a wide range of reliability or resilience tools should be identified to guide industry, regulators, and the ERO in effectively managing these risks. The industry must improve forward assessments of reliability and identify resilience activities that anticipate changes.

Key points on resiliency and recovery include:

- In 2016, the top Severity Risk Index days were a combination of many smaller local events, indicating that BPS resilience to the events during the year was high.[6] The ERO Enterprise, the impacted organizations, and the respective forums and trade organizations should perform post-event reviews to capture lessons learned and how to reduce the impact of future events.
- While the industry operates to the next worse contingency, the industry should be aggressive in identifying single points of vulnerability.
- Continue to leverage the North American Generator Forum (NAGF), North American Transmission Forum (NATF), Electric Power Research Institute (EPRI), and other industry-practice-sharing forums to enhance resilience and recovery.
- Leverage data sources such as event analysis, near miss databases, the Transmission Availability Data System (TADS), the Generating Availability Data System (GADS), the Demand Response Availability Data System (DADS), relay misoperations, EOP-004/OE-417 reports, and ac equipment failures to identify patterns and risks.
- Highlight applicable metrics in the *State of Reliability* report as benchmarks for resilience and recovery.
- Continue to include resilience goals in the ERO Enterprise's Strategic Plan.

The ERO Enterprise must have a complete understanding of the changing nature of, and associated risks to, the BPS. This includes a more comprehensive analysis of the BPS using NERC's special assessments. Further, markets and other tariffs will influence the changing nature of the reliability behavior of the power system and can provide the full complement of services required for the continued reliable operations of the BPS. The work on ERS is vital to understand the minimum requirements surrounding frequency response, voltage, and ramping resulting from the acceleration of the changing resource mix.

Adequate Data Visibility

Data is needed to understand the performance of and risks to the BPS. This includes information regarding distributed energy resources. Several profiles recommend the ERO Enterprise and industry use "bigger data" from multiple sources and larger areas to identify and manage risks. It is imperative that data requirements also include: 1) the data needed from distributed energy resources, including any necessary aggregated forms of data; 2) the entities should provide the data to system operators and planners; 3) logistics for how the data will be exchanged; 4) the frequency of the data updates; and 5) security and confidentiality measures for protecting necessary data.

Accurate Models

Since the rate of change of the resource mix is increasing, planners will place more emphasis on interconnection-wide studies that require improvement to and integration of regional models. In addition, enhancements to models will be needed to support probabilistic analysis to accommodate the energy limitations of resource additions (such as variable renewable resources). Resource adequacy must look beyond the calculation of reserve margins which assume actual capacity available during peak hours. More comprehensive dynamic load models will also be needed. One of the ways in which the industry can understand the system is by monitoring load characteristics and its changing nature due to distributed energy resources.

Natural Gas Deliverability and Other Co-dependencies

One common underlying risk that can be tied to multiple profiles is the increased use of just-in-time fuel delivery. More specifically, several profiles identify challenges from the single points of failure caused by the

[6] See the *2017 State of Reliability* report.

increased penetration of natural gas as a base load fuel. Natural gas fuel supply and its deliverability impacts reliability and must be fully studied to identify necessary mitigation strategies, including market, infrastructure, or regulatory solutions. The increased dependency on natural gas as a predominant fuel source presents challenges in real-time to system operators, and situational awareness must now include gas sources, pipeline, gas storage, infrastructure maintenance, compressor station location and failures, and deliverability concerns. Further, potential cyber or physical attack on a pipeline highlights the need for increased coordination among pertinent information sharing and analysis centers (ISACs) and the industry to improve response and recovery times due to the interdependency of the gas and electric system. The ability to model and address fuel limitations or shortages in BPS planning is a critical part of system planning. Therefore, there is a need for improved models as well as required data and information to support this planning to ensure the continued reliable operation of the BPS.

The BPS is also becoming more dependent on other sectors such as telecommunications for visibility and control. Coordination between sectors should be enhanced to mitigate vulnerabilities that significantly impact the reliability and resilience of the BPS.

Chapter 2: Prioritization of Inherent Reliability Risks

Figure 2.1 shows each of the identified inherent risk profiles mapped against likelihood and impact scales, which indicates the unmitigated or inherent risks of each risk profile as determined by the RISC. The risk map shows the committee's assessment of how the inherent risks of the profiles have changed from the 2016 report. The colored numbered circles show the committee's assessment of inherent risks for 2017. For those risks that have shifted, the shaded numbered circles represent the location from the 2016 report, with an arrow showing the movement for 2017. Profiles 1, 7, and 9 are the only ones that moved. Profile 4 has also moved, but does not show movement with an arrow, as the profile was redrafted from Asset Management and Maintenance to focus on Increasing Complexity in Protection and Control Systems. All other risks remained in the same location as in the 2016 report.

Further, the colors of the circles in Figure 2.1 represent the High, Moderate, and Lower levels of risk discussed in Chapter 1.

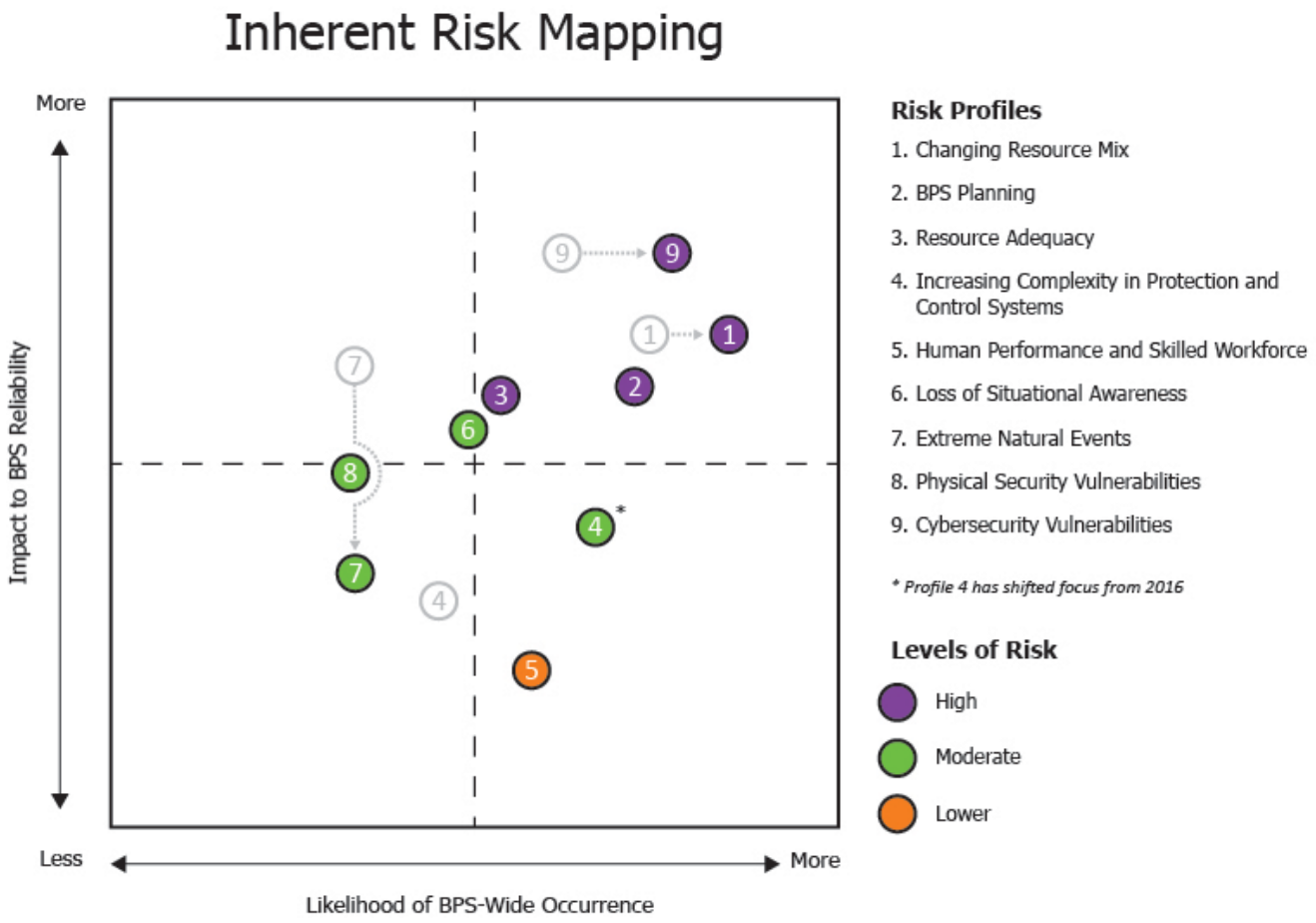


Figure 2.1: Risk Map of ERO Risk Profiles

Risk Groupings

High Priority Risks:

- **Cybersecurity Vulnerability**: The likelihood of this risk increased, while impact to reliability remains the same as the last review based on the judgment of the committee. Cyber threats are becoming more sophisticated and increasing in number, based on experience from attacks in other countries and on other industries. Exploitation of cybersecurity vulnerabilities can cause loss of control or damage to BPS-related voice communications, data, monitoring, protection and control systems, or tools. A large cyber-attack can result in equipment damage, degradation of reliable operations, uncontrolled cascading of the BPS, and loss of load. Further, cybersecurity vulnerabilities can come from several sources, both internal and external, and in some instances the utility may have its cybersecurity fully tested.
- **Changing Resource Mix:** The probability of this risk has increased, while the impact remained the same. The rapid rate at which fuel costs, subsidies, and federal, state, and provincial policies are affecting the resource mix are creating a new paradigm in which planners, balancing authorities, and system operators are reacting to resource additions and retirements. Further, the integration of new technologies and distributed energy resources are affecting the availability of as well as the ability of operators to see and control resources within their area.
- **Bulk-Power System Planning:** The likelihood and impact from BPS planning remained the same. It is closely tied to the changing resource mix as planners lack the ability to update or create system models and scenarios of potential future states to identify system needs based on the dynamic nature of the system. This changing system makes it increasingly difficult to evaluate BPS stability, including inertia and frequency response, voltage support (adequate dynamic and static reactive compensation), and ramping constraints.
- **Resource Adequacy and Performance:** The likelihood and impact from this risk remained the same. The changing resource mix and the integration of new technologies are altering the operational characteristics of the grid. Failure to take into account these changing characteristics and capabilities can lead to insufficient capacity and ERS to meet customer demands. This profile focuses on the development of better tools, metrics, and analysis to assess resource adequacy and performance.

Moderate Priority Risks:

- **Increasing Complexity in Protection and Control Systems:** The profile from 2016 regarding Asset Management and Maintenance was revised to focus on the increasing complexity in protection and control systems to support integration of new technologies. The need to properly design, coordinate, commission, operate, maintain, prudently replace, and upgrade BPS assets is increasing to prevent the potential for more frequent and wider-spread outages. These disruptions could be initiated or exacerbated by protection and control system misoperations or failures. Asset management strategies are evolving to include cyber security, resiliency, and recovery from high impact, low frequency events.
- **Loss of Situational Awareness**: This profile explains that the loss of situational awareness can be a precursor or contributor to a BPS event. It also highlights emerging challenges with visibility into distributed energy resource impacts on the grid. Loss of situational awareness due to insufficient communication and data regarding neighboring entities' operations is a risk as operators may act on incomplete information.
- **Extreme Natural Events:** The impact from these events have not lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System. These events have been contained to the local area experiencing the natural event, though the likelihood of occurrence remained the same. The committee believed the impact is better reflected by decreasing from last year's report because although there have been more severe weather events, the grid has

responded well. Severe weather or other natural events (e.g., hurricanes, tornadoes, protracted extreme temperatures, geomagnetic disturbances (GMDs), flooding, earthquakes, forest fires, extreme icing, etc.) are some of the leading causes of outages, and the industry must remain vigilant in improving preparation and coordination in order to minimize the effect of such events.

- **Physical Security Vulnerabilities**: Like cybersecurity, there is an increasing and evolving threat profile from physical attacks. Intentional damage, destruction, or disruption to facilities can potentially cause localized to extensive interconnection-wide BPS disruption for an extended period.

Lower Priority Risks:

- **Human Performance and Skilled Workforce:** There continues to be a need for skilled workers, such as protection engineers, to prevent both active and latent errors both of which negatively affect reliability.

Perspectives and Conclusions

The preceding summarizes the RISC's conclusions regarding key reliability risks and areas requiring focus to preserve reliability in 2018 and beyond. These observations and conclusions are supported by the collective expertise within the RISC as well as the other inputs outlined in the report. Overall, these inputs provide a strong foundation for the NERC Board of Trustees for consideration as an important input to ERO Enterprise Long-Term Strategy and Operating Plan, as well as ERO Enterprise resource planning and allocation.

Chapter 3: Risk Profiles

Risk Profile #1: Changing Resource Mix

Statement of the Risk

Today's resource mix has continued to evolve with the addition of emerging technologies like inverter generation based resources, improving storage techniques, and federal, state, and provincial renewable favoring policies. Transmission Planners, Balancing Authorities, asset owners, and system operators of the BPS may not have sufficient time to develop and deploy plans in response to reliability considerations resulting from the new resource mix.

Level of Risk

High Priority

Descriptors of the Risk

1. The intensity and pace of change (penetration rates of certain resources) and the types of change (the specific resources) are influenced by policy and economic factors in addition to state, provincial, and federal initiatives, which sometimes influence one region, province, or state in a certain direction more than another. Since the BPS is interconnected, these effects cannot be isolated to stay within political boundaries. Over time, regulatory initiatives, along with expected lower production costs and aging generation infrastructure, will likely alter the nature, investment needs, and dispatch of generation considering the replacement of large rotating synchronous central-station generators with natural-gas-fired generation, renewable forms of asynchronous generation, demand response, storage, smart- and micro-grids, and other technologies. Planners and operators may be challenged to integrate these inputs and make necessary changes.
2. The ability of regulators and industry to foresee and address reliability issues associated with these changes to the resource mix is complicated by:
    a. Ancillary services, such as the ERS (e.g., voltage control and reactive support, frequency response, ramping/balancing, blackstart) on the BPS, could be further eroded by the retirement of many large rotating synchronous central station generating units.
    b. The integration of large amounts of new resource technologies, distributed energy resources, and behind-the-meter resources; the lack of low-voltage ride through; inaccurate load data to accurately forecast anticipated demand; and the inability to observe and control distributed energy resources.
    c. The need for data and information about the character of resources in the planning, operational planning, and operating time horizons so the system can be planned and operated while accounting for the contributions and implications to reliability of all resources, regardless of their location or configuration.
    d. The interaction and performance of control systems during transient events may result in new common-mode failures that may not have been anticipated, for example, the inverter performance as demonstrated during the Blue Cut fire event.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise and industry need to provide more effective guidance to evaluate and improve controllable device settings[7] and how the interaction between these devices can affect BPS reliability, particularly during transient conditions.
2. The ERO Enterprise and industry should continue to place stronger emphasis on review and analysis of power system events, including those that are lower impact, to discover potential reliability trends early in their lifecycles.
3. NERC and industry should continue to conduct interconnection-wide technical studies and assessments, such as studies and assessments of frequency and inertia response, voltage support, short-circuit analysis, and inter-area oscillation.
4. The ERO Enterprise and Planning Coordinators need to continue to conduct electric and gas inter-dependency studies to identify BPS reliability risks and solutions including opportunities for more resilience producing coordination between electric and gas industries.
5. The ERO Enterprise should augment new systems being developed to gather data and insights into distributed energy resources (i.e., customer, distribution, or otherwise), and Reliability Coordinators should formulate plans to achieve the appropriate level of transparency and control such that implications to the BPS can be better understood.
6. Expand the collaboration, through the technical committees, with the Regional Transmission Operators (RTO)/Independent System Operators (ISOs) Council, Balancing Authorities in non-RTO/ISO market areas, other registered entities, and regulators on ERS recommendations for effective implementation as they emerge.
7. The ERO Enterprise should continue to provide independent technical assessments of the reliability impacts from the changing resource mix driven by proposed state, provincial, or federal statutes and transmission provider tariffs.
8. Policy makers should promote and engage in high-level collaboration among market operators (RTOs/ISOs), balancing authorities in non-RTO/ISO market areas, and provinces and states to establish long-term strategies for aligning policies with reliability needs.

Long-term (greater than 5-year time frame):

9. The ERO Enterprise should continue working with industry stakeholders and policy makers on reliability attributes essential to support the long-term reliability of the BPS, including equipment controls that enable system support from variable energy resources, improved visualization of dynamic/transient and voltage risks to the BPS, and accommodating distributed energy resources such as small end-use customer resources.

[7] For example, inverter based resources, protective relay schemes, remedial action schemes, static synchronous compensators (STATCOMs)/static VAR compensators (SVCs), generation distributed control systems, power system stabilizers, etc.

Risk Profile #2: Bulk-Power System Planning

Statement of the Risk

BPS planning is transitioning from centrally planned and constructed resources based on forecasted load growth and reliability projects to more reactive, rather than proactive, planning based on the integration of new resources and technologies driven by policies and incentives. Due to the lack of visibility, certainty, and speed that these resources are being integrated in some areas, planners may lack the ability to timely update or create system models and scenarios of potential future states to identify system reliability needs. Planners may be challenged to implement mitigation plans or reliability upgrades to address likely scenarios, driving the need for more real-time operating procedures.

Level of Risk

High Priority

Descriptors of the Risk

1. Planning and operating the BPS is becoming more complex due to:
    a. The increased and accelerated rate of plant retirements, especially conventional synchronous generation, coupled with the increasing integration of renewable, distributed, and asynchronous resources.
    b. Increased risks with the transition from a balanced resource portfolio, addressing fuel and technology risks, to one that is predominately natural gas and variable energy resources.
2. Incomplete information exists to perform BPS transient, mid-term, long-term, and small-signal stability studies, including consideration of interaction of BPS and resource controls, inertia/frequency response, voltage support (adequate dynamic and static reactive compensation), and ramping/balancing constraints due to the timing and dynamic performance of the new resource mix that changes throughout the day.
3. The ability to perform accurate long-term planning assessments is more difficult due to:
    a. The need for more comprehensive load models.
        i. The uncertainty and lack of visibility into load composition and resource mix along with imprecise or evolving models.
        ii. Complex load model and interaction with power electronics devices on a large scale at the distribution level that may affect BPS operations during disturbances (e.g., fault-induced delayed voltage recovery).
    b. An increasing need for transmission and system planning activities to include distributed energy resources; however, limited data availability, information sharing, enhanced models required for both system and electro-magnetic transients, and a lack of coordination can hinder the ability of planners to complete this analysis.
    c. The increased deployment of distributed energy resources within the distribution or behind-the-meter configurations will impact how the BPS responds.
    d. Uncoordinated integration of controllable device settings and power electronics installed to stabilize the system.
4. Common mode or single points of failure, such as fuel delivery systems, are emerging or have yet to be determined or evaluated.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. NERC should work with industry and manufacturers and developers of asynchronous resources to develop accurate dynamic models and make them available.
2. The ERO Enterprise should identify the type and periodicity of information needed from distributed energy resources to improve load forecasting and generator modeling and address coordination requirements between BPS and distribution system planners and operators to account for the uncertainty introduced by integration of variable generation, including the impact of weather on these resources.
3. NERC, working with the industry and forums, should develop guidelines and good industry practices for developing and maintaining accurate system and electromagnetic models that include the resources, load, and controllable devices that provide ERS, including the addition of benchmarking of dynamic models with Phasor Measurement Units (PMU) measurements based on actual system response to disturbance.
4. NERC should continue to collaborate with Planning Coordinators to expand development of interconnection-wide models with expected dispatches to support effective long-term planning assessments.

Mid-term (3–5 year time frame):

5. NERC should identify potential modifications to Reliability Standards necessary to address emerging risks, including impacts associated with ERS, if any.
6. The ERO Enterprise should collaborate with Planning Coordinators to assess the impact on reliability from well-head, storage, and fuel delivery issues and how to assess them in long-term planning studies.
7. NERC should coordinate with Planning Coordinators to continually review existing and identify new planning methods and tools needed to respond to the changing system.

Long-term (greater than 5-year time frame):

8. Encourage vendors of power system simulation software to develop programs to enhance dynamic load modeling capabilities.
9. The ERO Enterprise should consider the increasing reliability and security interdependencies between the U.S., Canada, and Mexico.

Risk Profile #3: Resource Adequacy and Performance

Statement of the Risk

The resource mix and its delivery is transforming from large, remotely-located coal and nuclear-fired power plants, towards gas-fired, renewable energy limited, distributed energy resources, and other emerging technologies. These changes in the generation resource mix and the integration of new technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability. Failures to take into account these characteristics and capabilities can lead to insufficient capacity, energy, and ERS to meet customer demands.

Level of Risk

High Priority

Descriptors of the Risk

1. The traditional methods of assessing resource adequacy may not accurately or fully reflect the new resource mix ability to supply energy and reserves for all operating conditions.
2. Forecasting BPS resource requirements to meet customer demand is becoming more difficult due to the penetration of distributed energy resources, which can mask the customer's electric energy use and the operating characteristics of distributed resources without sufficient visibility.
3. Conventional steam resources that operate infrequently due to economics may not operate reliably when dispatched for short peak-demand periods during seasonally hot or cold temperatures.
4. Historic methods of assessing and allocating ancillary services such as regulation, ramping, frequency response, and voltage support may not ensure ERS or sufficient contingency reserves are available at all times during real-time operations.
5. Fuel constraints and environmental limitations may not be reflected in resource adequacy assessments.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise and the industry should continue to develop improved modeling and probabilistic methods to evaluate resource adequacy. This includes assessments of emerging trends and insights for resource planning and operating models. Adequacy review should include evaluation of augmenting the existing and new measurements of ERS, coordination of controls, balancing load with resources, and resource adequacy in light of installed and available capacity from variable generation.
2. NERC should assess the recommendations from the *Bulk Power System Impacts Due to Disruptions on the Natural Gas System* special assessment and make recommendations on mitigation strategies to address the reliability issues identified.
3. The ERO Enterprise and the industry should continue to expand the use of probabilistic approaches to develop resource adequacy measures that reflect variability and overall reliability characteristics of the resources and composite loads, including non-peak system conditions.
4. Improve load forecasting which takes into account behind-the-meter resources, generator modeling, and coordination between BPS and distribution system planners and operators by analyzing data requirements necessary to ensure there is sufficient detail on the capability and performance of the BPS as it is impacted by distributed energy resources. The industry should gather data beyond simple demand forecasts and expand to identify resource capacity, location, and ERS capability. Regulatory support for common interconnection standards will be important for planning and analysis.

5. The ERO Enterprise and industry should continue to assess vulnerabilities from fuel availability as part of evaluating adequacy and capability to deliver resources.

Risk Profile #4: Increasing Complexity in Protection and Control Systems

Statement of the Risk

Failure to properly design, coordinate, commission, operate, maintain, prudently replace, and upgrade BPS control system assets could negatively impact system resiliency and result in more frequent and wider-spread outages initiated or exacerbated by protection and control system misoperations or failures. Asset management strategies are evolving to include greater amounts of digital network based controls for substation assets that introduce cyber security risks.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. Extended outage time needed to recover from compounding equipment outages.
2. A lack of sufficient analytics and awareness of inadequately maintained or conditioned equipment at or above minimum standards or requirements.
3. Increasingly complex protection and control systems that must be properly designed, coordinated, managed, and maintained to prevent or mitigate events.
4. BPS remedial action scheme failures as well as protection and control system misoperations exacerbate the impact from events, which significantly increases the risk for uncontrolled cascading of the BPS.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. Continue to conduct webinars on event lessons learned.
2. Continue to evaluate performance trends using additional data collected by event analysis to extract insights, issues, and trends for dissemination across industry participants.
3. Industry forums and trade groups should share successful asset management programs and lessons learned to gain insights on trends and increase dissemination of good industry practices.
4. NERC should work with industry experts and the forums to develop industry guidelines on protection and control system management to improve performance.
5. The ERO Enterprise should determine whether enhancements are required to the current family of protection and control (PRC) standards or related NERC guidance materials.

Mid-term (3–5 year time frame):

6. The ERO Enterprise should encourage industry forums, research organizations, and technical committees to share technologies or processes on condition monitoring, failure prevention, spare sharing, resiliency, and recovery.
7. The ERO Enterprise should provide the technical basis for BPS resiliency enhancements.

Long-term (greater than 5-year time frame):

8. The industry should implement good industry practices from the sharing of technologies or processes that aid in condition monitoring, failure prevention, spare sharing, resiliency, and recovery.

9. Recognize the risks of shorter technology lives for protection and controls systems and the need to implement replacement programs which do not impact BPS reliability.

Risk Profile #5: Human Performance and Skilled Workforce

Statement of the Risk

The BPS is becoming more complex, and as the industry faces turnover in technical expertise, it will have difficulty staffing and maintaining necessary skilled workers. The addition of significant internal procedural controls needed to maintain compliance with reliability and CIP compliance requirements has brought additional complexity to many skilled worker positions. In addition, inadequate human performance (HP) makes the grid more susceptible to both active and latent errors, negatively affecting reliability. HP weaknesses may hamper an organization's ability to identify and address precursor conditions to promote effective mitigation and behavior management.

Level of Risk

Lower Priority

Descriptors of the Risk

1. Organizations not implementing improvements based on past events, experiences, good industry practices or keeping an eye on the implementation of new technologies can hinder future operations improvements; gaps in skillsets or organizational improvement must be a priority.
2. Significant increase in operational complexity resulting in more extensive training needs associated with new technology and related compliance control strategy.
3. Turnover of key skilled or experienced workers (e.g., relay technicians, operators, engineers, IT support, and substation maintenance) will lead to more protection and control system misoperations.
4. Complicated new multi-discipline control and protection schemes which are beyond the skillset of the existing workforce.
5. A lack of training programs prevents closing skillset gaps quickly.
6. Inadequate management oversight or controls leads to organizational weaknesses and inefficiencies.
7. Ineffective corrective actions lead to repeated human performance errors.
8. Legacy systems and new technology result in disparity of the skillsets needed for BPS reliability.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise and industry forums should expand their communication and encourage sharing of good industry practices for increasing HP effectiveness (publishing lessons learned/good industry practices and supporting the NERC and NATF HP conference and other related workshops).
2. NERC should encourage industry and trade associations to identify skill gaps and develop recommendations to address them (e.g., curricula, programs, industry support, and educational pipeline programs), including those which may be associated with protection and control schemes.
3. The trade associations and industry should promote expanding training and education programs to include HP and recruitment of the next generations of skilled workers.
4. The ERO Enterprise and the industry should promote the use of NERC cause codes to establish a common understanding of HP triggers, collect and evaluate trends in data, and develop metrics as needed.

5. The industry should develop a near-miss database to leverage data sources such as event analysis, Transmission Availability Data System (TADS), Generating Availability Data System (GADS), Demand Response Availability Data System (DADS), relay misoperations, EOP-004/OE-417 Reports, and AC equipment failures to identify patterns and risk.

Mid-term (3–5 year time frame):

6. Consider and implement high-value recommendations developed to address skills gaps identified in the short-term mitigation mentioned in the 1–2 year time frame.
7. Work with organizations and vendors to improve the programming process to minimize programming errors for protective devices. Work with IEEE Power and Energy Society to develop guidelines to reduce human programming errors.

Long-term (greater than 5-year time frame):

8. Industry and trade organizations, such as NATF, should develop and implement a sustainable process to analyze and disseminate good industry practices for HP.
9. Industry standards and regulatory rules should consider the human skill set changes and training needs as part of their development.
10. Increase the integration of compliance requirements into operating practices.

Risk Profile #6: Loss of Situational Awareness

Statement of the Risk

Information sharing will be vital for visibility and a complete understanding of the impacts and contributions of distributed energy resources to the BPS. Inadequate situational awareness can be a precursor or contributor to BPS events. Loss of situational awareness can also occur when control rooms are not staffed properly or operators do not have sufficient information and visibility to manage the grid in real-time. Additionally, insufficient communication and data regarding neighboring entity's operations is a risk as operators may act on incomplete information.

Level of Risk

Moderate Priority

Descriptors of the Risk

The following items can lead to inappropriate operator response or lack of action:

1. Limited real-time visibility to and beyond the immediate neighboring facilities.
2. A lack of common status information on infrastructures and resources on which operators rely (e.g., gas, dispersed resources, distributed energy resources, and data and voice communications).
3. Information overload during system events.
4. Inadequate tools or fully capable back-up tools to address reliability.
5. Lack of training on the tools and information to assess system reliability at a given point in time.
6. Incomplete data and model accuracy used to feed into real-time operations.
7. Dependency on telecommunications systems for situational awareness.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise should continue to perform a root cause or common mode failure analysis of partial and full loss of key Energy Management System (EMS) capability using events analysis information and provide lessons learned and recommendations to reduce the likelihood of failure.
2. The ERO Enterprise should evaluate whether key applications are over reliant on a service provider and identify mitigating actions to reduce the risk.
3. Work with the forums on an approach for ongoing identification, cataloging, and sharing of good practices related to operating tools.
4. The ERO Enterprise should develop a guideline for industry use in addressing data modeling and information sharing.
5. The ERO Enterprise should identify the type and frequency of information needed from distributed energy resources for real-time situational awareness.
6. Identify best practices in telecommunications infrastructure architecture and design.

Mid-term (3–5 year time frame):

7. NERC, in concert with industry and trade organizations, should improve its set of real-time indicators of interconnection health.

8. NERC should engage industry and trade organizations to develop a list of key tasks and learning objectives for wide-area monitoring as well as assess the status following system events, including the expanded use of synchrophasor data.
9. NERC should work with industry to engage EPRI to develop a supplement or companion to the *Interconnected Power System Dynamics Tutorial* that deals with wide-area monitoring under a changing resource mix based on the near-term deliverables above.
10. The industry, trade organizations, and other industry groups such as the North American Synchrophasor Initiative (NASPI) should develop a suite of supplemental tools that use synchrophasor data (e.g., state estimator, contingency analysis, etc.) to improve situational awareness, provide early warning for operators regarding deteriorating conditions, and assist in recovery from disturbances.
11. Evaluate the risks of private telecommunication systems as compared to use of public systems for Supervisory Control and Data Acquisition (SCADA) systems.

Long-term (Greater than 5-year time frame):

12. The ERO Enterprise should engage with industry and trades organizations to identify options for the delivery of data critical for situational awareness in situations where EMS systems are down for extended periods.
13. The ERO Enterprise should work with industry and EMS vendors to establish forums to identify options for improving situational awareness tools utilizing EMS data including the integration of synchrophasor data.

Risk Profile #7: Extreme Natural Events

Statement of the Risk

Severe weather or other natural events are one of the leading causes of outages. Severe weather can cause BPS equipment damage, fuel limitations, and disruptions of voice and data communications, which can cause loss of load for an extended period.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. Lack of preparation for GMD events could lead to widespread loss of load due to voltage instability in certain regions.
2. Widespread damage to certain types of BPS infrastructure can extend outages due to unavailability of nearby replacement equipment or specialized capabilities.
3. Physical damage to equipment and fuel supply sources, such as natural gas pipelines or other energy storage facilities including hydro.
4. Damage to voice and data communications, as well as water supplies, can make certain critical facilities vulnerable and reduce the ability to serve load.
5. The industry does not have full knowledge, shared documentation, or coordination in accessing and assessing compatibility of the existing spare equipment inventory across geographical and political boundaries.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. E-ISAC and industry should continue to expand communications among ISACs, including the Telecommunications, Water, and Natural Gas ISACs.
2. Study multiple simultaneous limitations on natural gas deliveries during extreme weather.
3. Participate in exercises that incorporate extreme physical events and implement recommendations from exercises or drills such as GridEx.
4. Incorporate E-ISAC and Electricity Subsector Coordinating Council (ESCC) communications protocols into industry disaster preparedness processes.
5. National government agencies (e.g., Department of Energy, Natural Resources Canada, Secretaría de Energía (SENER)), industry, trades, and forums should identify appropriate mitigations to prevent spare equipment gaps and improve transportation logistics.
6. The ERO Enterprise and the industry should expand sharing of good industry practices and lessons learned regarding coordination among Reliability Coordinators, Balancing Authorities, and Transmission Operators during extreme weather events.
7. NERC and industry should plan a workshop that is coordinated with U.S., Canadian, and Mexican federal agencies and governmental authorities to address high-impact low-frequency event response, recovery, and communications vulnerabilities.

Mid-term (3–5 year time frame):

8. Identify and promote specific resiliency (i.e. recovery from a severe event) good industry practices to plan for extreme events.
9. Coordinate with the U.S., Canadian, and Mexican energy regulatory agencies and industry to support power transformer reserve programs and develop further reserve sharing methods as practical.
10. NERC should conduct detailed special assessments that integrate:
    a. Interdependencies in addition to fuel-related, such as telecommunications and water supply.
    b. Analytic data trend insights regarding resiliency under severe weather conditions, identifying preventable aspects for BPS reliability.
11. Better understand the interdependence of the telecommunication infrastructure and electric infrastructure during a natural disaster.

Long-term (greater than 5-year time frame):

12. Analyze data from GMD events to further the understanding of geomagnetically induced current effects on Bulk Electric System facilities to support enhancements to models and standards.
13. To facilitate preparedness, consider preparing sensitivity analyses to simulate the impacts from the most extreme natural events experienced to date in a planning area.

Risk Profile #8: Physical Security Vulnerabilities

Statement of the Risk

Intentional damage, destruction, or disruption to facilities can cause localized to extensive interconnection-wide BPS disruption potentially for an extended period.

Level of Risk

Moderate Priority

Descriptors of the Risk

1. Evolving threat around physical attacks, including EMP.
2. The exposed nature of parts of the grid makes it difficult to protect.
3. Long lead times associated with manufacturing and replacing some equipment, which can increase complexity of restoration after physical attacks that damage BPS equipment.
4. Incorrect assumptions on availability of replacement equipment.
5. Physical damage to generation fuel sources, such as natural gas pipelines, which will degrade the reliable operations of the BPS.
6. Damage to necessary telecommunications and water supplies, which will make certain critical facilities vulnerable and reduce the ability to serve load.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. The ERO Enterprise should develop performance metrics measuring and prioritizing potential physical attacks that will result in system disturbances while differentiating them from vandalism or theft incidents.
2. Assess the risks of physical attack scenarios on midstream or interstate natural gas pipelines, particularly where natural gas availability will impact generation and the reliability of the BPS.
3. Promote existing and new efforts to improve a spare equipment strategy and prioritization.
4. Industry should develop a catalog of regional/national exercises that incorporate extreme physical security events and share with industry, thus supporting increased participation across industry. Whenever possible, expand exercises to include more facilities and industries.
5. The forums and trades should perform the following activities:
    a. Identify and promote specific resiliency and vulnerability assessment good industry practices with planning for extreme events, including good physical security assessment practices.
    b. Develop an event guideline outlining prevention strategies and event response and recovery protocols for sabotage scenarios.
6. The industry should engage regulatory authorities to evaluate mechanisms for cost recovery of implementing specific resiliency strategies by the industry.
7. Industry should continue to work with the technical committees and forums to develop mitigation strategies and physical security assessment good industry practices.
8. Expand participation in security exercises in order to reflect extreme physical events.

9. Facilitate planning considerations to reduce the number and exposure of critical facilities to attack.
10. Encourage governmental entities to improve information sharing with industry.
11. Based on recommendations and identified risks outlined in EPRI's EMP report[8] and soon to be released results for EMP shielding requirements, determine the need to develop Reliability Standards, reliability guidelines, industry webinars, or additional analysis to address EMP events as necessary.
12. NERC should seek input from water, telecommunications, and gas ISACs in the development of physical security Reliability Standards.

Mid-term (3–5 year time frame):

13. Conduct a special regional assessment that addresses natural gas availability and pipeline impacts under physical attack scenarios.
14. National government agencies (e.g., Department of Energy, Natural Resources Canada, Secretaría de Energía (SENER)), industry, trades, and forums should identify appropriate mitigation strategies to fill spare equipment gaps and transportation logistics shortcomings.

Long-term (greater than 5-year time frame):

15. Foster the development and communication of methods, models, and tools to simulate system reliability impacts for the planning and operational planning time horizons.
16. Working with relevant governmental entities and industry, the ERO Enterprise should identify and evaluate the risk of potential long-term and advanced physical threats to the BPS and recommend preferred mitigation measures.

[8] *See* "Magnetohydrodynamic Electromagnetic Pulse Assessment of the Continental U.S. Electric Grid: Geomagnetically Induced Current and Transformer Thermal Analysis"*:* https://publicdownload.epri.com/PublicDownload.svc/product=000000003002009001/type=Product

Risk Profile #9: Cybersecurity Vulnerabilities

Statement of the Risk

Exploitation of cybersecurity vulnerabilities can potentially result in loss of control or damage to BPS-related voice communications, data, monitoring, protection and control systems, or tools. Successful exploitation can damage equipment, causing loss of situational awareness and, in extreme cases, can result in degradation of reliable operations to the BPS, including loss of load.

Level of Risk

High Priority

Descriptors of the Risk

1. Cybersecurity threats result from exploitation of both external and internal vulnerabilities:
    a. Exploitation of employee and insider access.
    b. Weak security practices of host utilities, third-party service providers and vendors[9], and other organizations.
    c. Unknown, undisclosed, or unaddressed vulnerabilities in cyber systems.
    d. Growing sophistication of bad actors, nation states, and collaboration between these groups.
2. Interdependencies from the critical infrastructure sectors, such as Communications, Financial Services, Oil and Natural Gas Subsector, and Water, where sector-specific vulnerabilities can impact BPS reliability.
3. Legacy architecture coupled with the increased connectivity of the grid expands the attack surface of BPS protection and control systems:
    a. Increased automation of the BPS through control systems implementation.
    b. The trend towards increased integration of IT operating systems may increase in the attack surface and associated attack risk.
    c. IT/operational technology (OT) control system infrastructure management, out-of-date operating systems, and the lack of patching capability/discipline.
4. Technologies and services
    a. Increased reliance on third party service providers and cloud-based services for BPS operations and support.
    b. Cyber security risks in the supply chain: software integrity and authenticity; vendor remote access; information system planning; and vendor risk management and procurement controls.
5. Ineffective teamwork and collaboration among the federal, provincial, state, local government, private sector and critical infrastructure owners can exacerbate cyber events.
6. A lack of staff that is knowledgeable and experienced in cybersecurity of control systems and supporting IT/OT networks (historically separate organizations and skillsets). This risk is symptomatic across all industries and is a risk because it hinders an organization's ability to prevent, detect, and respond to cyber incidents due to organizational silos.

[9] *See* Reliability Standard CIP-013-1, Supply Chain Risk Management: http://www.nerc.com/pa/Stand/Reliability%20Standards/CIP-013-1.pdf.

7. The rapid growth in sophistication and widespread availability of tools and processes designed to exploit vulnerabilities and weaknesses in BPS technologies and in connected IT networks and systems.

Recommendations for Mitigating the Risk

Near-term (1–2 year time frame):

1. In collaboration with the Critical Infrastructure Protection Committee (CIPC) and industry stakeholders, develop a risk process to address the potential impacts of cyber security threats and vulnerabilities.
2. The E-ISAC should continue information sharing protocols among interdependent ISACs to increase the visibility into cyber and physical security threats.
3. The E-ISAC should continue outreach to industry to increase registration and utilization of the E-ISAC portal.
4. The E-ISAC should mature the cybersecurity risk information sharing program (CRISP) and encourage expanded participation.
5. NERC and the CIPC should prioritize lessons learned from regional and national exercises (e.g., GridEx) and publish lessons learned and guidelines as needed.
6. Facilitate planning considerations to reduce the number and exposure of critical cyber facilities to attack.
7. The industry should encourage the development of a peer review process for emerging risks.
8. The ERO Enterprise should develop metrics regarding the trend of cyber-attacks and potential threats.
9. The industry should develop focused training and education programs to address the shortage of skilled and experienced cybersecurity professionals, as well as IT professionals with BPS operations experience.
10. The ESCC should operationalize the framework of cyber mutual assistance to address issues with recovery after a cyber-attack.
    a. Evaluate security operations centers that incorporate the BPS (IT/OT convergence areas).
    b. Continue to conduct more frequent, smaller-scale cybersecurity exercises to hone the response skills of industry professionals and strengthen inter-organizational relationships.

Mid-term (3–5 year time frame):

11. The ERO Enterprise should develop a feedback mechanism from CIP standards implementation to evaluate the standard and lessons learned from new technology deployments.
12. The ERO Enterprise with industry should develop agreed-upon levels of cyber-resilience suitable for BPS planning and operations.

Long-term (greater than 5-year time frame):

13. The ERO Enterprise and industry should develop methods, models, and tools to simulate cyber impacts on system reliability, enabling BPS planning to withstand an agreed-upon level of cyber resiliency.
14. The ERO Enterprise and industry should develop industry operating guidelines that incorporate an agreed-upon level of cyber resilience.
15. With industry participation, the ERO Enterprise should develop guidelines for the integration of new technologies while maintaining or enhancing the agreed-upon level of cyber resilience.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** System Operating Limits Methodology for the Operations Horizon

2. **Number:** FAC-011-~~3~~4

3. **Purpose:** ~~-~~To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Reliability Coordinator

5. **Effective Date:** ~~——~~ See Implementation Plan for ~~the Revised Definition of "Remedial Action Scheme".~~Project 2015-09.

B. Requirements and Measures

R1. ~~The~~Each Reliability Coordinator shall have a ~~documented~~ methodology for ~~use in developing~~establishing SOLs (i.e., SOL Methodology) within its Reliability Coordinator Area. ~~This~~*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology.

~~R1.~~R2. Each Reliability Coordinator shall~~:~~ include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** Be applicable for developing SOLs used in the operations horizon.~~

~~**1.2.** State that SOLs shall not exceed associated Facility Ratings.~~

M2. ~~Include a description of how to identify the subset of SOLs that qualify~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R2.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.3.~~ Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as ~~IROLs.~~

3.1. ~~The~~ specified in the Reliability Coordinator's SOL Methodology ~~shall include a requirement that SOLs provide BES~~ ;

3.2. Require that System Voltage Limits respect the Facility voltage Ratings;

3.3. Require that System Voltage Limits are higher than in-service under voltage load shedding (UVLS) relay settings;

3.4. Identify the lowest allowable System Voltage Limit;

3.5. Address the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;

3.6. Address coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area; and

3.7. Address coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R3.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~1.4.~~4.1. Specify stability performance ~~consistent with~~ criteria, including any margins applied. The criteria shall include the following:

4.1.1. ~~In the pre-contingency~~ steady-state~~, the BES shall demonstrate~~ voltage stability;

4.1.2. transient~~, dynamic and~~ voltage response;

4.1.3. angular stability; ~~all Facilities shall be within their Facility Ratings and within their thermal, voltage and~~ and

4.1.4. System damping.

4.2. Require that stability limits~~. In~~ are established to meet the ~~determination of SOLs,~~criteria specified in Part 4.1 for the ~~BES condition used shall reflect current or expected system~~Contingencies identified in Requirement R5.

4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.

~~1.5.~~4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions ~~and shall reflect~~ including any changes to ~~system~~System topology such as Facility outages~~.~~ ;

~~**1.6.** Following the single Contingencies[1] identified in Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.~~

4.5. ~~Single line to~~ Describe the level of detail that is required for the study model(s); including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6. Describe the allowed uses of Remedial Action Schemes and other automatic post-Contingency mitigation actions; the planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R4.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analysis (OPAs) and Real-time Assessments (RTAs). The method shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1. Loss of any of the following either by single phase to ground or ~~3-~~three phase Fault (whichever is more severe~~),~~) with ~~Normal Clearing, on any Faulted~~ normal clearing, or without a Fault:

- generator~~, line, ~~;
- transmission circuit;
- transformer~~, or ~~;
- shunt device~~.~~; or

~~**1.6.1.** Loss of any generator, line, transformer, or shunt device without a Fault.~~

- ~~Single~~single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

~~**1.7.** In determining the system's response to a~~ Any additional types of single Contingency~~, the following shall be acceptable:~~

~~[1] The Contingencies identified in FAC-011-R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.~~

~~**1.7.1.** Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.~~

~~**1.7.2.** Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies~~

~~**1.7.3.** System reconfiguration through manual or automatic control or protection actions.~~

~~**1.8.** To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the transmission system, and the transmission system topology.~~

~~**R2.** The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:~~

~~**2.1.** Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)~~

~~**2.2.** Selection of applicable Contingencies~~

5.2. ~~A process for determining which of the~~ events identified for use in determining stability limits~~ associated with the list~~, or for use in performing OPAs and RTAs.

5.3. Any types of multiple ~~contingencies (~~Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

~~**2.3.**~~**5.4.** The method for considering the Contingency events provided by the Planning ~~Authority~~Coordinator in accordance with FAC-~~014~~015-1, Requirement ~~6) are applicable for use in the operating horizon given the actual or expected system conditions.~~ R6 to identify the Contingencies for use in determining stability limits.

~~**2.3.1.** This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.~~

~~**2.4.** Level of detail of system models used to determine SOLs.~~

~~**2.5.** Allowed uses of Remedial Action Schemes.~~

~~**2.6.** Anticipated transmission system configuration, generation dispatch and Load level~~

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R5.

R6. Each Reliability Coordinator shall include in its SOL Methodology: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

6.1. A description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs).

~~**2.7.**~~**6.2.** Criteria for determining when violating a SOL qualifies as an ~~Interconnection Reliability Operating Limit (~~IROL~~)~~ and criteria for developing any associated IROL T_V.

M6. ~~The~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R6.

R7. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its Reliability Coordinator(s). The method shall address the periodicity of SOL communication. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation of its SOL Methodology that addresses the items listed in Requirement R7.

~~**R3.**~~**R8.** Each Reliability Coordinator shall ~~issue~~provide its SOL Methodology and any changes to ~~that methodology,~~the SOL Methodology prior to the effective date of the SOL Methodology, to ~~the effectiveness of the Methodology or of a change to the Methodology, to all of the following: :~~ *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

~~**3.1.**~~**8.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that ~~indicated~~requests and indicates it has a reliability-related need ~~for the methodology.~~;

8.2. Each Planning ~~Authority~~Coordinator and Transmission Planner that ~~models~~is responsible for planning any portion of the Reliability ~~Coordinator's~~Coordinator Area;

~~**3.2.**~~**8.3.** Each Transmission Operator within its Reliability Coordinator Area.

~~**3.3.** Each Transmission Operator~~ Acceptable evidence that ~~operates in~~ the Reliability Coordinator ~~Area.~~

~~C. Measures~~

~~**M1.** The Reliability Coordinator's SOL Methodology shall address all of the items listed in Requirement 1 through Requirement 3.~~

~~**M2.**~~**M8.** ~~The Reliability Coordinator shall have evidence it issued~~provided its SOL Methodology~~, and any changes to that methodology, including the date they were issued, in accordance~~ to the entities identified in Requirement R8 may include, but is

not limited to, dated electronic or hard copy documentation such as emails with Requirement 4. receipts, registered mail receipts, or postings to a secure web site with accompanying notification(s).

D.C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring ResponsibilityEnforcement Authority:
Regional Reliability Organization

1.2. Compliance Monitoring Period and Reset Time Frame

Each Reliability Coordinator shall self-certify its compliance to the Compliance Monitor at least once every three years. New Reliability Authorities shall demonstrate compliance through an on-site audit conducted by the Compliance Monitor within the first year that it commences operation. The Compliance Monitor shall also conduct an on-site audit once every nine years and an investigation upon complaint to assess performance.

The Performance-Reset Period shall be twelve months from the last non-compliance.

Data"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.3.1.2. Evidence Retention:
The Reliability Coordinator shall keep all superseded portions to its SOL Methodology for 12 months beyond the date of the change in that methodology. In addition, entities found non-compliant shall keep information related to the non-compliance until found compliant

The Compliance Monitor shall keep the last audit and all subsequent compliance records.

1.4. Additional Compliance Information

The Reliability Coordinator shall make the following available for inspection during an on-site auditThe following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by theits Compliance Monitor or within 15

business daysEnforcement Authority to retain specific evidence for a longer period of a requesttime as part of an investigation upon complaint:.

1.4.1 SOL Methodology.

1.4.2 Superseded portionsThe Reliability Coordinator shall keep data or evidence of its SOL Methodology that had been made within the past 12 months.

1.4.3 Evidence that the SOL Methodology and any changes to the methodology that occurred within the past 12 months were issued to all required entities.

2. Levels of Non-Compliance for Western Interconnection: (To be replaced with VSLs once developed and approved by WECC)

2.1. Level 1: There shall be a level one non-compliance if either of the following conditions exists:

2.1.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded.

- **Level 2:** The SOL Methodology did not include a requirement to address all of the elements in R3.1, R3.2, R3.4with Requirements R1 through R3.7 and E1R8 for the current year plus the previous 12 calendar months. .

2.2. Level 3: There shall be a level three non-compliance if any of the following conditions exists:

2.2.1 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to one of the three types of single Contingencies identified in R2.2.

2.2.2 The SOL Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not include evaluation of system response to two of the seven types of multiple Contingencies identified in E1.1.

2.2.3 The System Operating Limits Methodology did not include a statement indicating that Facility Ratings shall not be exceeded and the methodology did not address two of the six required topics in R3.1, R3.2, R3.4 through R3.7.

2.3. Level 4: The SOL Methodology was not issued to all required entities in accordance with R4.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels~~:~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.
~~R1~~**R2.**	~~Not applicable.~~ N/A	~~The Reliability Coordinator has a documented SOL Methodology for use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.2~~N/A	The Reliability Coordinator ~~has a documented~~ included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations, but the method did not address the use ~~in developing SOLs within~~of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area~~, but it does not address R1.3.~~	The Reliability Coordinator ~~has a documented~~ did not include in its SOL Methodology the method for ~~use in developing SOLs within its Reliability Coordinator Area, but it does not address R1.1~~Transmission Operators to determine the applicable owner-provided Facility Ratings to be used~~.~~ ~~OR~~ ~~The Reliability Coordinator has no documented SOL Methodology for use~~ in ~~developing SOLs within its Reliability Coordinator Area.~~operations.

~~R2~~**R3.**	The Reliability Coordinator~~'s~~ failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance following single contingencies, but does not require that SOLs are set to meet BES performance in the pre-contingency state. (R2.1)~~ .	~~Not applicable.~~The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator~~'s~~ failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology ~~requires that SOLs are set to meet BES performance in the pre-contingency state, but does not require that SOLs are set to meet BES performance following single contingencies. (R2.2 – R2.4)~~.	~~The Reliability Coordinator's SOL Methodology does not require that SOLs are set to meet BES performance in the pre-contingency state and does not require that SOLs are set to meet BES performance following single contingencies. (R2.1 through R2.4)~~The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.
~~R3~~ **R4.**	The Reliability ~~Coordinator's~~Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but one of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but two of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's~~Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology ~~includes a description for all but three of the following: R3.1 through R3.7~~.	The Reliability ~~Coordinator's SOL Methodology is missing a description of~~Coordinator failed to incorporate four or more of the ~~following: R3.1 through R3.7~~Parts of Requirement R4 into its SOL Methodology.
R5.	N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of

				Requirement R5 into its SOL Methodology.
~~R3.6~~**R6.**	N/A	N/A	~~N/A~~The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_V) in its SOL Methodology.	~~N/A~~The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.
R7.	N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the

			Transmission Operator established.	periodicity of SOL communication.
~~R4~~**R8.**	The Reliability Coordinator ~~failed to issue~~provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to one of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology was provided to one or more of the required entities before the effectiveness of the change,~~accordance with Part 8.4 but was ~~provided to all the required entities no more~~late by less than or equal to 10 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator ~~failed to issue~~ provided its new or revised SOL Methodology ~~and/or one or more changes to that methodology to two of the required entities specified~~to a requesting Reliability Coordinator in ~~R4.1, R4.2, and R4.3.~~ ~~OR~~ ~~For a change in methodology, the changed methodology~~ accordance with Part 8.4, but was ~~provided to one or more of the required entities~~late by more than 10 calendar days ~~after the effectiveness of the change, but~~ but less than or equal to 20 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or~~to one ~~or more changes to that methodology to three~~ of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was~~ The Reliability Coordinator provided ~~to one or more of required entities~~its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days ~~after the effectiveness of the change, but~~ but less than or equal ~~to30~~to 30 calendar days ~~after the effectiveness of the change~~.	The Reliability Coordinator failed to ~~issue~~provide its new or revised SOL Methodology ~~and/or one or more changes~~ to ~~that methodology to four~~two or more of the ~~required entities~~parties specified in ~~R4~~Parts 8.1~~, R4.2, and R4~~ through 8.3. OR ~~For a change in methodology, the changed methodology was provided~~ The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the ~~required entities more than30~~parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a

				requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days~~ after the effectiveness of the change~~. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4.

~~E.~~D. Regional ~~Differences~~Variances

~~3.~~ The following Interconnection-wide Regional Difference shall be applicable in the Western Interconnection:

~~3.1.~~ As governed by the requirements of R3.3, starting with all Facilities in service, shall require the evaluation of the following multiple Facility Contingencies when establishing SOLs:

~~3.1.1~~ Simultaneous permanent phase to ground Faults on different phases of each of two adjacent transmission circuits on a multiple circuit tower, with Normal Clearing. If multiple circuit towers are used only for station entrance and exit purposes, and if they do not exceed five towers at each station, then this condition is an acceptable risk and therefore can be excluded.

~~3.1.2~~ A permanent phase to ground Fault on any generator, transmission circuit, transformer, or bus section with Delayed Fault Clearing except for bus sectionalizing breakers or bus-tie breakers addressed in E1.1.7

~~3.1.3~~ Simultaneous permanent loss of both poles of a direct current bipolar Facility without an alternating current Fault.

~~3.1.4~~ The failure of a circuit breaker associated with a Remedial Action Scheme to operate when required following: the loss of any element without a Fault; or a permanent phase to ground Fault, with Normal Clearing, on any transmission circuit, transformer or bus section.

~~3.1.5~~ A non-three phase Fault with Normal Clearing on common mode Contingency of two adjacent circuits on separate towers unless the event frequency is determined to be less than one in thirty years.

~~3.1.6~~ A common mode outage of two generating units connected to the same switchyard, not otherwise addressed by FAC-011.

~~3.1.7~~ The loss of multiple bus sections as a result of failure or delayed clearing of a bus tie or bus sectionalizing breaker to clear a permanent Phase to Ground Fault.

~~3.2.~~ SOLs shall be established such that for multiple Facility Contingencies in E1.1.1 through E1.1.5 operation within the SOL shall provide system performance consistent with the following:

~~3.2.1~~ All Facilities are operating within their applicable Post-Contingency thermal, frequency and voltage limits.

~~3.2.2~~ Cascading does not occur.

~~3.2.3~~ Uncontrolled separation of the system does not occur.

~~**3.2.4** The system demonstrates transient, dynamic and voltage stability.~~

~~**3.2.5** Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall security of the interconnected transmission systems.~~

~~**3.2.6** Interruption of firm transfer, Load or system reconfiguration is permitted through manual or automatic control or protection actions.~~

~~**3.2.7** To prepare for the next Contingency, system adjustments are permitted, including changes to generation, Load and the transmission system topology when determining limits.~~

~~**3.3.** SOLs shall be established such that for multiple Facility Contingencies in E1.1.6 through E1.1.7 operation within the SOL shall provide system performance consistent with the following with respect to impacts on other systems:~~

~~**3.3.1** Cascading does not occur.~~

~~**3.4.** The Western Interconnection may make changes (performance category adjustments) to the Contingencies required to be studied and/or the required responses to Contingencies for specific facilities based on actual system performance and robust design. Such changes will apply in determining SOLs.~~

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to October 1, 2008 Changed "Cascading Outage" to "Cascading" Replaced Levels of Non-compliance with Violation Severity Levels Corrected footnote 1 to reference FAC-011 rather than FAC-010	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order 705	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	February 7, 2013	R5 and associated elements approved by NERC Board of Trustees for retirement as part of the Paragraph 81 project (Project 2013-02) pending applicable regulatory approval.	
2	November 21, 2013	R5 and associated elements approved by FERC for retirement as part of the Paragraph 81 project (Project 2013-02)	
2	February 24, 2014	Updated VSLs based on June 24, 2013 approval.	
3	November 13, 2014	Adopted by the NERC Board of Trustees	Replaced references to Special Protection System and SPS with Remedial Action Scheme and RAS
~~3~~4	~~November 19, 2015~~	~~FERC Order issued approving FAC-011-3. Docket No. RM15-13-000.~~Project 2015-09 – Adopt revisions to standard.	Revisions

Mapping Document

Project 2015-09 Establish and Communicate System Operating Limits

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R1. The Reliability Coordinator shall have a documented methodology for use in developing SOLs (SOL Methodology) within its Reliability Coordinator Area. This SOL Methodology shall:	FAC-011-4, Requirement R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	No change.
FAC-011-3, Requirement R1, R1.1. [This SOL Methodology shall] Be applicable for developing SOLs used in the operations horizon.	This requirement was removed.	The stated purpose of FAC-011-4 is "To ensure that System Operating Limits (SOLs) used in the reliable operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies." The title of FAC-011-4 is "System Operating Limits Methodology for the Operations Horizon". Therefore, every requirement in FAC-011-4 is intended for developing SOLs used in the operations horizon. Accordingly, there is no reliability-

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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		related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon.
FAC-011-3, Requirement R1, R1.2. [This SOL Methodology shall] State that SOLs shall not exceed associated Facility Ratings.	This requirement is addressed in proposed FAC-011-4 Requirement R2 in conjunction with the definitions for Operational Planning Analysis and Real-time Assessment in the NERC Glossary of Terms. FAC-011-4 Requirement R2: Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for*	Facility Ratings to be used in operations as SOLs is addressed through FAC-011-4, Requirement R2. Facility Ratings that are determined per Requirement R2 are a required input for Operational Planning Analyses (OPA) and Real-time Assessments (RTA) per the definitions, and therefore address the analysis of system performance with respect to Facility Ratings. Facility Rating exceedances are determined through OPAs and RTAs.

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	next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through*	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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	internal systems or through third-party services.)"	
FAC-011-3, Requirement R1, R1.3. [This SOL Methodology shall] Include a description of how to identify the subset of SOLs that qualify as IROLs.	FAC-011-4, Requirement R6 and Part 6.1. R6. Each Reliability Coordinator shall include in its SOL Methodology 6.1. A description of how to identify the subset of SOLs that qualify as IROLs.	The language from the approved standard was maintained in the proposed FAC-011-4.
FAC-011-3, Requirements R2, R2.1 and R2.2. R2. The Reliability Coordinator's SOL Methodology shall include a requirement that SOLs provide BES performance consistent with the following: R2.1 In the pre-contingency state, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages.	These requirements are addressed in: 1. TOP and IRO requirements for TOPs and RCs to perform OPAs, to develop Operating Plans for SOL exceedances identified in those OPAs, to perform RTAs, and to implement Operating Plans to address SOL exceedances identified in those RTAs. 2. The definition of OPA and RTA 3. FAC-011-4, Requirement R4 addresses the establishment of stability limits and the associated performance requirements. 4. FAC-011-4 Requirement R6 and its Parts relating to IROLs.	"BES performance" as stated in FAC-011-3 Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the Transmission Operator (TOP) standards, SOL exceedance triggers the development and

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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R2.2. Following the single Contingencies identified in Requirement R2, R2.2.1 - R2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.	5. The definition of IROL and the TOP and IRO standards that address operation within IROLs. TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). TOP-001-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. TOP-001-4, Requirement R13: Each Transmission Operator shall ensure that a Real-time Assessment is performed at least once every 30 minutes. TOP-001-4, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL	implementation of an Operating Plan to address that SOL exceedance. The items in approved FAC-011-3, Requirement R2 and its sub-requirements are addressed through the related TOP standards that reference SOL exceedance. 1. Per TOP-002-4, Requirement R1, TOPs have OPAs to identify SOL exceedances. 2. Per TOP-002-4, Requirement R2, TOPs develop Operating Plans for SOL exceedances identified in the OPA. 3. Per TOP-001-3, Requirement R13, TOPs perform RTAs at least once every 30 minutes to identify SOL exceedances. 4. Per TOP-001-3, Requirement R14, TOPs implement Operating Plans to mitigate SOL exceedances. 5. Per IRO-008-2, Requirement R1, RCs perform OPAs to identify SOL and IROL exceedances.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	exceedance identified as part of its Real-time monitoring or Real-time Assessment. IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating Reliability Limits (IROLs) within its Wide Area. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. IRO-008-2, Requirement R4: Each Reliability Coordinator shall ensure that a Real-time	6. Per IRO-008-2, Requirement R2, RCs develop coordinated Operating Plans for SOL and IROL exceedances identified in its OPA. 7. Per IRO-008-2, Requirement R4, RCs perform RTAs at least once every 30 minutes to identify SOL and IROL exceedances. 8. Per IRO-008-2, Requirement R5, RCs notify TOPs and BAs of SOL or IROL exceedances identified in its RTA. The portion of FAC-011-3, Requirement R2, R2.1 that states *"In the determination of SOLs, the BES condition used shall reflect current or expected system conditions and shall reflect changes to system topology such as Facility outages"* is addressed specifically by FAC-011-4 Requirement R4, Part 4.4 which requires that System conditions including any changes to System topology such as Facility outages are to be included as part of the process for determining stability limits. While stability

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	Assessment is performed at least once every 30 minutes. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the results of a Real-time Assessment indicate an actual or expected condition that results in, or could result in, a System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status*	limits are frequently dependent on system conditions and Facility outages, Facility Ratings and System Voltage Limits are not dependent on system conditions and Facility outages. However, system conditions and topology changes such as Facility outages are critical for determining whether or not Facility Ratings and System Voltage Limits are being exceeded for the pre- or post-Contingency state, which is accomplished through performing OPAs and RTAs that address expected and actual system conditions and Facility outages for the pre- and post-Contingency state. Regarding the stability portions of Requirement R2, R2.1 and R2.2: FAC-011-4, Requirement R4 improve reliability by requiring the RC's SOL Methodology to address several stability-related phenomena and associated performance criteria in its SOL Methodology, as seen in Requirement R4, Part 4.1.

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	or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)" Real-time Assessment is defined in the NERC Glossary of Terms as *"An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)"*	Requirement R4, Part 4.2 requires the RC's SOL Methodology to require that stability limits be established to meet those performance requirements. Furthermore, Requirement R4, Part 4.6 requires the RC's SOL Methodology to specify how the RC establishes stability limits when there is an impact to more than one TOP in its Reliability Coordinator Area RC's SOL Methodology. Requirement R4 works together with FAC-014-3, Requirement R2 which requires TOPs to establish SOLs in accordance with the RC's SOL Methodology and with FAC-014-3, Requirement R4 which requires the RC to establish stability limits that impact more than one TOP in its RC Area. Instability is also addressed through FAC-011-4, Requirement R6 which requires the RC's SOL Methodology contain a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs), and through FAC-014-3, Requirement R1 which requires the

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-011-4 Requirement R4: Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping. 4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area.	RC to establish IROLs in accordance with its SOL Methodology. IRO-009-2, Requirement R3 requires the RC to act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_v, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. Additionally, TOP-001-3, Requirement R12 requires that the TOP not operate outside any identified IROL for a continuous duration exceeding its associated IROL T_V.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions. IROL is defined in the NERC Glossary of Terms as – *A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages that adversely impact the reliability of the Bulk Electric System.*	

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-011-4, Requirement R6: Each Reliability Coordinator shall include in its SOL Methodology: 6.1. A description of how to identify the subset of SOLs that qualify as IROLs. 6.2. Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V. FAC-014-3, Requirement R1: Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). IRO-009-2, Requirement R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an	

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	IROL exceedance is mitigated within the IROL's T_V, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. TOP-001-3, Requirement R12: Each Transmission Operator shall not operate outside any identified Interconnection Reliability Operating Limit (IROL) for a continuous duration exceeding its associated IROL T_V.	
FAC-011-3, Requirement R2, sub-requirements R2.2.1, R2.2.2, and R2.2.3 R2.2.1. Single line to ground or 3-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device. R2.2.2. Loss of any generator, line, transformer, or shunt device without a Fault. R2.2.3. Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	FAC-011-4, Requirement R5, Part 5.1.1 Loss of any of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer; • shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	The requirements in approved FAC-011-3 were consolidated into a single requirement in proposed FAC-011-4.

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Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and Requirement R2.4. R2.3 In determining the system's response to a single Contingency, the following shall be acceptable: R2.3.1. Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area. R2.3.2. Interruption of other network customers, (a) only if the system has already been adjusted, or is being adjusted, following at least one prior outage, or (b) if the real-time operating conditions are more adverse than anticipated in the corresponding studies R2.3.3. System reconfiguration through manual or automatic control or protection actions. R2.4 To prepare for the next Contingency, system adjustments may be made, including changes to generation, uses of the	The reliability issues denoted in FAC-011-3 Requirement R2.3, sub-requirements R2.3.1, R2.3.2, R2.3.3, and R2.4 represent a combination of issues that are relevant to the establishment of SOLs and those that are relevant to "how the system is to be operated." The issues that pertain to the establishment of SOLs are addressed through FAC-011-4 Requirement R4 : R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.1. Specify stability performance criteria, including any margins applied. The criteria shall include the following: 4.1.1. steady-state voltage stability; 4.1.2. transient voltage response; 4.1.3. angular stability; 4.1.4. System damping.	Requirement R2, R2.3 describes an acceptable System response to single Contingencies. These requirements are sub-requirements of Requirement R2, which addresses the establishment of SOLs that "provide a certain level of BES performance". "BES performance" as stated in FAC-011-3, Requirement R2 is not determined through SOLs in and of themselves. SOLs are an input into OPAs and RTAs. The OPA and RTA evaluation against those SOLs provide for reliable system performance by ensuring through these analyses/assessments that the system performs reliably in the pre- and post-Contingency states (i.e., that the system is within thermal (Facility Ratings), System Voltage Limits, and stability limits pre- and post-Contingency). If SOL exceedance is occurring, the system is not performing reliably. Per the TOP and IRO standards, RTAs must be performed at least once every 30 minutes. Accordingly, each new operating state is "studied" at least once every 30 minutes. Additionally, per the TOP

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
transmission system, and the transmission system topology.	4.2. Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5. 4.3. Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area. 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits. 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other	standards, SOL exceedance triggers the development and implementation of an Operating Plan to address that SOL exceedance. Insofar as the issues in FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to the establishment of SOLs, automatic control actions relevant to the establishment of stability limits are addressed in FAC-011-4 Requirement R4, Part 4.6 which requires the SOL Methodology to describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions as part of stability limit establishment. Accordingly, any RAS or automatic mitigation scheme (which includes those that interrupt customers or reconfigure the system) are required to be reflected in the establishment of stability limits per Requirement R4, Part 4.6. Furthermore, per Requirement R4, Part 4.4, stability limits are required to take into consideration the configuration of the system, which may include any necessary

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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	automatic post-Contingency mitigation actions. The issues that are more centric to "how the system is to be operated" are more appropriately addressed in the development and implementation of Operating Plans as denoted in the following standards: 1. TOP-002-4, Requirement R2: Each Transmission Operator shall have an Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) exceedances identified as a result of its Operational Planning Analysis as required in Requirement R1. 2. TOP-002-4, Requirement R3: Each Transmission Operator shall notify entities identified in the Operating Plan(s) cited in Requirement R2 as to their role in those plan(s). 3. TOP-002-4, Requirement R6: Each Transmission Operator shall provide	manual actions taken by the System Operator to configure the system in a manner that supports the use of a given stability limit. However, insofar as FAC-011-3, Requirement R2, R2.3 and R2.4 correlate to "how the system is to be operated", the operational decisions related to customer interruption and system reconfiguration are governed by the Operating Plan, if such actions are necessary to address SOL exceedance. The need for making system adjustments to prepare for the next Contingency is standard operational practice and does not need to be specified or required by the Reliability standards. Any such actions related to the interruption of customers, reconfiguration of the system, or operational preparations for the next Contingency are expected to be included in an Operating Plan, if such actions are required by System Operators to address SOL exceedances.

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	its Operating Plan(s) for next-day operations identified in Requirement R2 to its Reliability Coordinator. 4. TOP-012-3, Requirement R14: Each Transmission Operator shall initiate its Operating Plan to mitigate a SOL exceedance identified as part of its Real-time monitoring or Real-time Assessment. 5. IRO-008-2, Requirement R2: Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities. 6. IRO-008-2, Requirement R3: Each Reliability Coordinator shall notify	In the current body of TOP and IRO reliability standards, the Operating Plan is the mechanism for addressing SOL exceedances. The mitigation actions that System Operators take to prevent or address SOL exceedances are expected to be contained within the Operating Plan. TOPs need to have the flexibility in their Operating Plan to address the wide-ranging operational issues they may encounter. There is no reliability need for reliability standards to provide such highly prescriptive requirements which specify how TOPs are to operate the system. Because the development and implementation of Operating Plans is addressed in the current body of reliability standards, reliability is not compromised by the removal of FAC-011-3, Requirement R2, R2.3 and R2.4. Any concepts in this section may need to be retained are better suited in a Reliability Guideline (e.g., Reliability Guideline for the development of Operating Plans) rather

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	impacted entities identified in its Operating Plan(s) cited in Requirement R2 as to their role in such plan(s). 7. IRO-008-2, Requirement R5: Each Reliability Coordinator shall notify impacted Transmission Operators and Balancing Authorities within its Reliability Coordinator Area, and other impacted Reliability Coordinators as indicated in its Operating Plan, when the System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) exceedance identified in Requirement R5 has been prevented or mitigated.	than a NERC Reliability Standard requirement.
FAC-011-3, Requirement R3, R3.1 R3. The Reliability Coordinator's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including	FAC-011-3, Requirement R3, R3.1 and R3.4 both address the study model. These two requirements are addressed with the single requirement in proposed FAC-011-4, Requirement R4, Part 4.5. Facility Ratings are created and provided through FAC-008 and further examined

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
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R3.1 Study model (must include at least the entire Reliability Coordinator Area as well as the critical modeling details from other Reliability Coordinator Areas that would impact the Facility or Facilities under study.)	the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	through FAC-011-4, Requirement R2. System Voltage Limits are created per FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model. As a result, no study model reference is needed in FAC-011-4 for Facility Ratings or System Voltage Limits. However, for those RCs or TOPs that determine stability limits, a study model is needed to perform the "study". Therefore, the level of detail of the study model falls under the requirement associated with establishing stability limits (R4). FAC-011-4, Requirement R4, Part 4.5 affords the RC with the flexibility to the extent of the modeling area (including other RC areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide-area or inter-area instability). Part 4.5 acknowledges that some types of localized stability issues do not require a model of

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		the entire RC area to establish certain types of stability limits.
FAC-011-3, Requirement R3, R3.2 R3.2 [The RC's SOL Methodology shall include] Selection of applicable Contingencies	FAC-011-4, Requirement R5 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.1. The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs: 5.1.1. Loss of any of the following, either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault: • generator; • transmission circuit; • transformer;	All requirements regarding Contingencies are consolidated and addressed in proposed FAC-011-4, Requirement R5.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	• shunt device; • single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system. 5.2. Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs. 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.	
FAC-011-3, Requirement R3, R3.3 and R3.3.1. R3.3 [The RC's SOL Methodology shall include] A process for determining which of the stability limits associated with the list of	FAC-011-4, Requirement R5, Part 5.4 R5. Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and	FAC-011-4, Requirement R5, Part 5.4 and FAC-015-1 Requirement R6 address the reliability objective in FAC-011-3, Requirement R3, R3.3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
multiple contingencies (provided by the Planning Authority in accordance with FAC-014, Requirement 6) are applicable for use in the operating horizon given the actual or expected system conditions. R3.3.1. This process shall address the need to modify these limits, to modify the list of limits, and to modify the list of associated multiple contingencies.	multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include: 5.4. The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits. FAC-015-1 Requirement R6: R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:	In FAC-015-1, Requirement R6, the Planning Coordinator is required to identify and communicate any instability, Cascading, or uncontrolled separation, as well as the related information contained in the Parts of Requirement R6, to the RC and associated TOPs. Once the RC receives this information, the RC then applies the method required by FAC-011-4, Requirement R5, Part 5.4 for considering those Contingencies for use in determining stability limits. These requirements collectively address the reliability objectives of FAC-011-3, Requirement R3, R3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
FAC-011-3, Requirement 3, R3.4. R3.4 [The RC's SOL Methodology shall include] Level of detail of system models used to determine SOLs.	FAC-011-4, Requirement R4, Part 4.5 R4. Each Reliability Coordinator shall include in its SOL Methodology the method	Reference the explanation provided for FAC-011-3, Requirement R3, R3.1.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	for determining the stability limits to be used in operations. The method shall: 4.5. Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.	
FAC-011-3, Requirement R3, R3.5. R3.5 [The RC's SOL Methodology shall include] Allowed uses of Remedial Action Schemes.	FAC-011-4, Requirement R4, Part 4.6 R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.6. Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1]. Footnote 1 states "The planned use of underfrequency load-shedding (UFLS) is not allowed in the establishment of stability limits."	FAC-011-3, Requirement R3, R3.5 was carried over into FAC-011-4, Requirement R4, Part 4.6. The requirement has been clarified by including other automatic mitigation actions that are not a RAS, for example UVLS.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R3, R3.6. R3.6 [The RC's SOL Methodology shall include] Anticipated transmission system configuration, generation dispatch and Load level	FAC-011-4, Requirement R4, Part 4.4: R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall: 4.4. Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages; TOP-002-4, Requirement R1: Each Transmission Operator shall have an Operational Planning Analysis that will allow it to assess whether its planned operations for the next day within its Transmission Operator Area will exceed any of its System Operating Limits (SOLs). IRO-008-2, Requirement R1: Each Reliability Coordinator shall perform an Operational Planning Analysis that will allow it to assess whether the planned operations for the next-day will exceed System Operating Limits (SOLs) and Interconnection Operating	The requirements in FAC-011-3, Requirement R3, R3.6 are addressed in proposed FAC-011-4, Requirement R4, Part 4.4. Part 4.4 was included as a Part to Requirement R4 because the information is relevant to the establishment of stability limits. Facility Ratings are created and provided through FAC-008 and further examined through FAC-011-4, Requirement R2, and System Voltage Limits are created through FAC-011-4, Requirement R3. Neither of these types of SOLs are necessarily a byproduct of a "study" or study model that requires inclusion of the items in FAC-011-3, Requirement R3, R3.6. Additionally, TOP-002-4, Requirement R1 and IRO-008-2, Requirement R1 require the TOP and the RC respectively to have/perform an OPA. Per the definition of OPA, the OPA shall reflect applicable inputs which include the

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Reliability Limits (IROLs) within its Wide Area. Operational Planning Analysis is defined in the NERC Glossary of Terms as *"An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)"*	items required by FAC-011-3, Requirement R3, R3.6. Accordingly, when stability limits include the information required in Requirement R4, and the TOPs and RCs perform their required OPAs, the information in FAC-011-3, Requirement R3, R3.6 is inherently addressed.
FAC-011-3, Requirement R3, R3.7. R3.7 [The RC's SOL Methodology shall include] Criteria for determining when violating a SOL qualifies as an Interconnection Reliability	FAC-011-4, Requirement R6, Part 6.2 R6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and	The reliability objective of FAC-011-3, Requirement R3, R3.7 was carried over into FAC-011-4, Requirement R6, Part 6.2.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Operating Limit (IROL) and criteria for developing any associated IROL T_V.	criteria for developing any associated IROL T_V.	
FAC-011-3, Requirement R4 and Requirement R4.1: R4. The Reliability Coordinator shall issue its SOL Methodology and any changes to that methodology, prior to the effectiveness of the Methodology or of a change to the Methodology, to all of the following: R4.1. Each adjacent Reliability Coordinator and each Reliability Coordinator that indicated it has a reliability-related need for the methodology.	FAC-011-4, Requirement R8, Parts 8.1 and 8.4: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.1. Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology; 8.4. Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.	The reliability objective of FAC-011-3, Requirement R4 was carried over to FAC-011-4, Requirement R8, Parts 8.1 and 8.4 Clarifications were made in Part 8.1 that adjacent RCs include those within an Interconnection. This was added to clarify the intent of adjacent RCs for the purposes of communicating SOL Methodologies. These adjacent RCs are required to receive the SOL Methodology prior to the effective date of the Methodology because they can be directly impacted by it. Non-adjacent RCs, which are addressed in Part 8.4, do not require communication of the SOL Methodology prior to its effective date because these RCs are less likely to be directly impacted; however, provisions are made with Part 8.4 for non-adjacent RCs to obtain the SOL Methodology within 30 days of the request if they indicate a reliability-related need for it.

Standard FAC-011-3 - System Operating Limits Methodology for the Operations Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-011-3, Requirement R4, R4.2 R4.2 [communicate the SOL Methodology to] Each Planning Authority and Transmission Planner that models any portion of the Reliability Coordinator's Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.2 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The language was changed to better reflect the intent of the requirement. The requirement is intended to addresses PCs and TPs that are responsible for planning within the RC Area.
FAC-011-3, Requirement R4, R4.3 R4.3 [communicate the SOL Methodology to] Each Transmission Operator that operates in the Reliability Coordinator Area.	FAC-011-4, Requirement R8, Part 8.3 R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.3. Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The reliability objective of FAC-011-3, Requirement R4, R4.3 was carried over to FAC-011-4, Requirement R8, Part 8.3.

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Rationale for FAC-011-4

September 2017

Requirement R1

Each Reliability Coordinator shall have a methodology for establishing SOL (i.e., SOL Methodology) within its Reliability Coordinator Area.

Rationale R1

The three subparts in Requirement R1 in currently-effective Reliability Standard FAC-011-3 are either not necessary for reliability, or they are addressed through other mechanisms in FAC-011-4 and therefore are not included as part of Requirement R1.

Requirement R1.1 in currently-effective FAC-011-3 requires that the SOL Methodology shall be applicable for developing SOLs used in the operations horizon. The revised Requirement R1 is applicable to the Operations Planning Time Horizon. Accordingly, there is no reliability-related need to have a requirement specifying that the Reliability Coordinator's (RC's) SOL Methodology is applicable for developing SOLs used in the operations horizon. Additionally, the purpose of the standard references SOLs used in the reliable operation of the BES.

Requirement R1.2 in currently-effective FAC-011-3 requires that the SOL Methodology state that SOLs shall not exceed associated Facility Ratings. Facility Ratings to be used in operations as System Operating Limits (SOLs) are addressed through FAC-011-4 Requirement R2 and therefore is not addressed as a subpart of R1.

Requirement R1.3 in currently-effective FAC-011-3 requires that the SOL Methodology include a description of how to identify the subset of SOLs that qualify as Interconnection Reliability Operating Limits (IROLs). This language is preserved in Requirement R6.

Requirement R2

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.

Rationale R2

The reliability objectives of Requirement R2 are 1) to ensure that the owner-provided Facility Ratings that are selected for use in operations are determined in accordance with the RC's SOL Methodology, and 2) to ensure the consistent use of applicable Facility Ratings between RCs and their Transmission Operators (TOP). For example, if a Transmission Owner (TO) provides three levels of Facility Ratings pursuant to Reliability Standard FAC-008-3, and another TO provides five

levels of ratings, the RC will establish the method for the TOPs to determine which of those Facility Ratings will be utilized in common with the TOP and the RC for monitoring and assessments.

The intent of Requirement R2 is not to change, limit, or modify Facility Ratings determined by the equipment owner. The equipment owner is still responsible for determining the Facility Ratings per FAC-008. The intent is to use those owner-provided Facility Ratings in a consistent manner between the TOP and RC during operations.

Requirement R3

Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the System Voltage Limits to be used in operations. The method shall:

- **3.1** Require that BES buses/stations have an associated System Voltage Limit except for the BES buses/stations that may be excluded as specified in the Reliability Coordinator's SOL Methodology;
- **3.2** Require that System Voltage Limits respect the Facility voltage Ratings;
- **3.3** Require that System Voltage Limits are higher than in-service undervoltage load shedding (UVLS) relay settings;
- **3.4** Identify the lowest allowable System Voltage Limit;
- **3.5** Require the use of common System Voltage Limits between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area;
- **3.6** Require coordination of System Voltage Limits between adjacent Transmission Operators in its Reliability Coordinator Area;
- **3.7** Require coordination of System Voltage Limits between adjacent Reliability Coordinator Areas within an Interconnection.

Rationale R3

System Voltage Limits (SVLs) are intended to provide reliable pre- and post-contingency System performance for operations within a Reliability Coordinator Area and across neighboring Reliability Coordinator Areas. The proposed definition of System Voltage Limits includes normal and emergency voltage limits, and can also include time-based voltage limits, depending on what the RC requires. It is expected that the RC would require a set of System Voltage Limits to cover the entire BES system within its Reliability Coordinator Area for facility-based voltage limits, voltage instability, voltage collapse and misactuation of relay elements.

Both high and low limits are required. High limits tend to be associated with equipment/facility limitations. Low limits are often used to prevent phenomena associated with low voltages such as system instability, voltage collapse, and potential misactuation of relay elements. Identifying the set of "System Voltage Limits", both high and low, assures that all voltage limits associated with a particular bus or station, or the equipment connected to it, have been considered and the most limiting are used.

While all BES buses/stations have equipment related voltage ratings, there may be reasons that certain buses/stations do not require a System Voltage limit. Part 3.1 allows RCs to identify certain buses/stations that may be excluded from having an associated System Voltage Limit. These exempt buses/stations should be identified in the RC's SOL Methodology with appropriate reasoning. The identification of such buses/stations could be documented by citing the type of buses/stations (based on voltage level or area of the System) as opposed to a more detailed list of individual buses/stations which are exempt.

Buses or stations may not require System Voltage Limits when the voltage at the station has no material impact on System performance and associated SOLs. For example, System Voltage Limits at neighboring/nearby stations may be sufficient to protect the facilities from high voltage, and the System from instability, voltage collapse, and misactuation of relay elements.

Parts 3.5-3.7 identifies the RC as the entity responsible for developing the overall method for TOPs and RCs to determine and coordinate System Voltage Limits in their areas and neighboring areas.

Part 3.2 provides that in establishing System Voltage Limits, the SOL Methodology shall respect any Facility voltage Ratings established by the Generation Owner or TO under FAC-008. Recognizing that voltage limits are difficult to reflect by facility, the System Voltage Limits provided for stations/buses should reflect any Facility voltage Ratings for facilities that terminate at or are adjacent to the stations/buses with System Voltage Limits.

FERC Order No. 818 issued November 19, 2015, states that UVLS should not be triggered for an N-1 Contingency. As such, under Part 3.3, the SOL Methodology shall ensure System Voltage Limits are set above all UVLS settings to avoid UVLS operation following N-1 Contingencies.

Requirement R4

Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limits to be used in operations. The method shall:

4.1 Specify stability performance criteria, including any margins applied. The criteria shall include the following:

- **4.1.1** steady-state voltage stability;
- **4.1.2** transient voltage response;
- **4.1.3** angular stability;
- **4.1.4** System damping;

4.2 Require that stability limits are established to meet the criteria specified in Part 4.1 for the Contingencies identified in Requirement R5;

4.3 Describe how the Reliability Coordinator establishes stability limits when there is an impact to more than one Transmission Operator in its Reliability Coordinator Area;

4.4 Describe how instability risks are identified, considering levels of transfers, Load and generation dispatch, and System conditions including any changes to System topology such as Facility outages;

4.5 Describe the level of detail that is required for the study model(s), including the extent of the Reliability Coordinator Area, as well as the critical modeling details from other Reliability Coordinator Areas, necessary to determine different types of stability limits.

4.6 Describe the allowed uses of Remedial Action Schemes (RAS) and other automatic post-Contingency mitigation actions[1].

Rationale R4

Reliability Standard FAC-011-3 currently requires the System to demonstrate transient, dynamic and voltage stability for both pre- and post-contingent states, but does not provide specifics. By requiring specific stability criteria within the SOL Methodology, the standard is improved and provides greater clarity and uniformity on practices across the industry. The set of commonly used stability criteria specified in Requirement R4 Part 4.1 is based upon information provided by standard drafting team members and observers, including many RCs and TOPs. Industry input from areas with significant experience managing stability issues led to the inclusion of system damping.

Also included in Part 4.1 is language requiring the SOL Methodology to include descriptions of how margins are applied. This language was added to explicitly capture the practices in use by RCs for off-line or on-line calculated stability limits, including any margin used in the application of the stability limits. It is left to the RC what type of margin to use (a percentage of the limit or a fixed MW value, for example), if it uses one at all.

Requirement R4 Part 4.2 provides the link to the Contingencies which must be respected in operations, which are unchanged from the current standard. In response to industry comments, Contingency specifications were moved to a separate requirement.

Requirement R4 Part 4.3 was introduced to preclude ambiguity in the resolution of stability limits when multiple TOPs within an RC's footprint are impacted. For example, this requirement may be met by providing language in the SOL Methodology describing which TOP (or identifying that the RC) has the responsibility to determine stability SOLs impacting multiple TOPs, and could also determine how to choose between stability limits derived by multiple TOPs for the same stability limit exceedance.

Requirement R4 Parts 4.4, 4.5 and 4.6 require that the SOL Methodology provide a description of the key parameters that must be considered and monitored when performing analyses to determine the stability limits. The intent of these parts is to help ensure that the SOL Methodology provides guidance such that the process/method used by the RC to determine stability limits may be repeated, successfully, by anyone reading the SOL Methodology. For example, the SOL Methodology could state that stability limits will be determined for any combination of all facilities in and single facility out

[1] The planned use of underfrequency load shedding (UFLS) is not allowed in the establishment of stability limits.

conditions, for all valid transfer conditions for the highest allowable thermal transfer condition (i.e. winter ratings), plus a flow margin of 10%, to account for potential emergency transfer conditions. This level of detail would allow TOPs and other entities to consistently duplicate results from study to study. Part 4.5 combines FAC-011-3 Requirements R3.1 and R3.4 into a single part while providing flexibility to the extent of the Reliability Coordinator Area (including other Reliability Coordinator Areas) that must be modeled to reflect the varying needs for different types of stability limits (e.g. local single unit stability up to wide area or inter area instability). By recognizing that some types of localized stability issues do not require entire Reliability Coordinator Area modeling to establish a stability limit, this revision aligns with and promotes the ability to monitor these localized areas with real time stability analysis tools.

Requirement 4 Part 4.4 is specifically intended to address the need for the SOL Methodology to identify the method for ensuring stability limits are "valid" (i.e. provide stable operations pre- and post-Contingency) for the Operational Planning Analysis (OPA) and Real-time Assessments (RTA) for which they will be used. Since stability limits may vary based on the system topology, load, generation dispatch, etc., and the current definitions for OPA and RTA include "An evaluation of … system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for ….operations", the stability limits used in OPA/RTA should be "valid" for those system conditions.

As described within PRC-006-2 in alignment with FERC Order No. 763, underfrequency load shedding (UFLS) are designed "to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures." In the establishment of stability limits under Requirement R4 Part 4.6, UFLS programs are expressly prohibited from being considered as an acceptable post-Contingency mitigation action in order to preserve the intended availability of UFLS as a "last resort system preservation measure".

Requirement R5

Each Reliability Coordinator shall include in its SOL Methodology the method for identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs). The method shall include:

5.1 The following list of single Contingency events for use in determining stability limits and performing OPAs and RTAs:

5.1.1 Loss of any of the following either by single phase to ground or three phase Fault (whichever is more severe) with normal clearing, or without a Fault:

- generator;
- transmission circuit;
- transformer;
- shunt device;
- single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.

5.2 Any additional types of single Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.3. Any types of multiple Contingency events identified for use in determining stability limits, or for use in performing OPAs and RTAs.

5.4 The method for considering the Contingency events provided by the Planning Coordinator in accordance with FAC-015-1 Requirement R6 to identify the Contingencies for use in determining stability limits.

Rationale R5

Requirement R5 combines both the requirements for single Contingencies (formerly in Requirement R2.2 of FAC-011-3) and for multiple Contingencies (formerly in Requirement R3.3 of FAC-011-3) for ease of interpretation.

Furthermore, Requirement R5 continues to maintain the flexibility that existed in Requirement R2.2 and Requirement R3.3 for each RC to determine which additional single and multiple Contingencies to respect given the uniqueness of their system. Through both the feedback received as a result of the July 2016 informal posting and the May 2016 technical conference it was evident that both the drafting team and industry agree that sufficient flexibility is required for each RC to determine its own methodology for addressing Contingencies other than single Contingencies.

Requirement R5 mandates that the RC specify which types of Contingencies (both single and multiple) are used for determining stability limits as well as those used in checking for all types of SOL exceedances in OPAs and RTAs (thermal, voltage and stability limits). The SOL Methodology is the best place to communicate which Contingencies the RC is respecting in their footprint such that all TOPs and any neighboring RCs understand one another's internal and interconnection-related reliability objectives.

Requirement R5 Part 5.1.1 identifies the types of single Contingency events that at a minimum must be used for stability limit analysis and for performing OPAs and RTAs. However, other types of single Contingency events such as inadvertent breaker operation and bus faults may be considered if the probability of such an event is relevant. The method for determining those Contingencies must also be identified in the RC's methodology as per Requirement R5 Part 5.2.

Requirement R5 Parts 5. 1 through 5.4 require that differences in Contingency events for determining stability limits, those used for OPAs and those used for RTAs, be specified in the RC's methodology. It is important to distinguish between Contingencies used for determining stability limits and those that are actually applied in OPAs and RTAs as only specific system conditions may actually warrant their use in the days leading up to real-time operations. For example, multiple Contingencies at heightened risk under specific weather or system conditions may not need to be respected (and thus monitored) the majority of the time when these conditions are not present.

Requirement R5 Part 5.4 compliments the proposed Requirement R6 in FAC-015-1 by ensuring the RC's methodology describes how the Contingency event information from the Planning Coordinator is used in deriving stability limits used in operations.

Requirement R6

Each Reliability Coordinator shall include in its SOL Methodology:

6.1 A description of how to identify the subset of SOLs that qualify as IROLs.
6.2 Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V.

Rationale R6

The two IROL related requirements in FAC-011-3 were preserved under Requirement R6.

Requirement R7

Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Rationale R7

Requirement R7 serves as a companion to FAC-014-3 Requirement R3 which states, *"The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology."*

The language in Requirement R7 is written to provide clarity that the TOP is responsible for communicating only those SOLs that it established for its own Transmission Operator Area. The TOP is not responsible for communicating SOLs established by other TOPs that it uses in its analyses.

While it is possible to address communication of SOLs through TOP-003-3 and IRO-010-2, the standard drafting team determined that the communication of SOLs was of such importance to the reliability of the BES that it should be addressed specifically in the RC's SOL Methodology and in FAC-014-3. Additionally, the aforementioned Reliability Standards address the data specifically necessary for performing OPA, Real-time monitoring, and RTA. SOL information may be necessary for other uses beyond these analyses, for example in outage coordination assessments.

Requirement R8

Each Reliability Coordinator shall provide its new or revised SOL Methodology to:

8.1 Each adjacent Reliability Coordinator within its Interconnection prior to the effective date of the SOL Methodology;
8.2 Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;
8.3 Each Transmission Operator within its Reliability Coordinator Area prior to the effective date of the SOL Methodology;

8.4 Each requesting Reliability Coordinator that indicates a reliability-related need and is not considered adjacent in Part 8.1, within 30 calendar days of receiving the request.

Rationale R8

Requirement R8 preserves the reliability objective of providing the SOL Methodology to the appropriate entities from Requirement R4 of FAC-011-3. Requirement R8 Part 8.1 mandates that an RC provide its SOL Methodology to each adjacent RC within its Interconnection. In Requirement R8 Part 8.2, PC, not Planning Authority, was used to be consistent with the Functional Model as well as to be consistent with TPL-001. Requirement R8 Part 8.2 also uses “responsible for planning” instead of “models any portion of” to identify those PCs and TPs who have a reliability-related need rather than a PC/TP who simply has acquired a model that contains a portion of the Reliability Coordinator Area, but does not plan for that area. Requirement R8 Part 8.4 differs from Requirement R8 Parts 8.1 through 8.3 in that it mandates that an RC provide its SOL Methodology to any requesting RC that indicates a reliability-related need within 30 calendar days of such request rather than prior to the effective date of the SOL Methodology.

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Violation Risk Factor and Violation Severity Level Justifications

FAC-011-4 System Operating Limits Methodology for the Operations Horizon

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-011-4 System Operating Limits (SOL) Methodology for the Operations Horizon. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-011-4 Requirement R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-013-2, Requirement R1.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Not having a methodology for establishing SOLs has the potential unintended consequence of creating inconsistencies in establishing SOLs which could directly affect the electrical state or the capability of the Bulk Electric System (BES), or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-	The requirement contains one objective, therefore a single VRF is assigned.

mingle More than One Obligation	

VSLs for FAC-011-4, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not have a SOL Methodology for establishing SOLs within its Reliability Coordinator Area.

VSL Justifications for FAC-011-4, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R2	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of improper Facility Ratings could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator included in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations but the method did not address the use of common Facility Ratings between the Reliability Coordinator and the Transmission Operators in its Reliability Coordinator Area.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to determine the applicable owner-provided Facility Ratings to be used in operations.

VSL Justifications for FAC-011-4, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 sub-requirement R1.2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R3	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect System Voltage Limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R3 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R3 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R4	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard FAC-008-3, Requirements R2 and R3 which requires development of a methodology to determine certain ratings/limits.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator failed to incorporate one of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate three of the Parts of Requirement R4 into its SOL Methodology.	The Reliability Coordinator failed to incorporate four or more of the Parts of Requirement R4 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1 and Requirement R2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R5	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved Reliability Standard TPL-001-4, Requirement R3, Part 3.4, which requires development of a list of contingencies to be evaluated for System performance.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Incorrectly identifying the single Contingencies and multiple Contingencies for use in determining stability limits and performing Operational Planning Analyses (OPAs) and Real-time Assessments (RTAs) could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator failed to incorporate one of the Parts 5.2, 5.3 or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate two of the Parts 5.2, 5.3, or 5.4 of Requirement R5 into its SOL Methodology.	The Reliability Coordinator failed to incorporate Part 5.1 of Requirement R5 into its SOL Methodology. OR The Reliability Coordinator failed to incorporate Parts 5.2, 5.3, and 5.4 of Requirement R5 into its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3, sub-requirements R3.2, R3.3, and R3.3.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R6	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of High for this requirement is consistent with approved Reliability Standard FAC-014-2, Requirements R1, R3, and R4 which requires development of Interconnection Reliability Operating Limits (IROLs) to be consistent with a methodology.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator failed to include Part 6.1 (a description of how to identify the subset of SOLs that qualify as IROLs) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (a criteria for determining when violating a SOL qualifies as an IROL) in its SOL Methodology. OR The Reliability Coordinator failed to include Part 6.2 (criteria for developing any associated IROL T_v) in its SOL Methodology.	The Reliability Coordinator failed to include Parts 6.1 and 6.2 in its SOL Methodology.

VSL Justifications for FAC-011-4, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R1, sub-requirement R1.3 and Requirement R3, sub-requirement R3.7. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R7	
Proposed VRF	**Medium**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements (Parts) so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of medium for this requirement is consistent with approved other standards in the BAL, COM, EOP, IRO, and TOP families that require notification to other entities for situational awareness of the BES.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to communicate identified SOLs could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator did not include in its SOL Methodology the periodicity of SOL communications for Transmission Operators to communicate SOLs the Transmission Operator established.	The Reliability Coordinator did not include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established or the periodicity of SOL communication.

VSL Justifications for FAC-011-4, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-011-4 Requirement R8	
Proposed VRF	**Lower**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	This Guideline is no longer applicable since sub-requirements (Parts) utilize the same VRF assigned to the main requirement.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of lower for this requirement is consistent with approved Reliability Standard FAC-010-3, Requirement R4, FAC-011-3, Requirement R4, and FAC-013-2, Requirement R2 which requires notification of a new or revised methodology to other entities.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to provide its SOL methodology to entities within and adjacent to its Reliability Coordinator Area could affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of this requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-011-4, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4 but was late by less than or equal to 10 calendar days.	The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 10 calendar days but less than or equal to 20 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to one of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 20 calendar days but less than or equal to 30 calendar days.	The Reliability Coordinator failed to provide its new or revised SOL Methodology to two or more of the parties specified in Parts 8.1 through 8.3. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to one or more of the parties specified in Parts 8.1 through 8.3 prior to the effective date of the SOL Methodology. OR The Reliability Coordinator provided its new or revised SOL Methodology to a requesting Reliability Coordinator in accordance with Part 8.4, but was late by more than 30 calendar days. OR The Reliability Coordinator failed to provide its new or revised SOL Methodology to a requesting Reliability

			Coordinator in accordance with Part 8.4.

VSL Justifications for FAC-011-4, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs map to the currently-effective FAC-011-3 Requirement R4. The proposed VSLs do not lower the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15
Draft Reliability Standard posted for Informal Comment Period	07/14/16 – 08/12/16

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – October 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-2~~2~~3

3. **Purpose:** To ensure that System Operating Limits (SOLs) used in the reliable ~~planning and~~ operation of the Bulk Electric System (BES) are determined based on an established methodology or methodologies.

4. **Applicability:**

4.1. Functional Entities:

4.1.1. Reliability Coordinator

~~**1.1.** Planning Authority~~

~~**1.2.** Transmission Planner~~

4.1.2. Transmission Operator

~~**2. Effective Date:** April 29, 2009~~

5. Effective Date: See Implementation Plan for Project 2015-09.

B. Requirements and Measures

~~The~~

R1. Each Reliability Coordinator shall ~~ensure that SOLs, including~~ establish Interconnection Reliability Operating Limits (IROLs~~),~~) for its Reliability Coordinator Area ~~are~~in accordance with its System Operating Limit Methodology (SOL Methodology). *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established ~~and that the SOLs (including Interconnection Reliability Operating Limits) are consistent~~IROLs in accordance with ~~its~~it SOL Methodology.

R2. ~~The~~Each Transmission Operator shall establish ~~SOLs (as directed by its Reliability Coordinator~~System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area ~~that are consistent~~in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission Operator established SOLs in accordance with its Reliability Coordinator's SOL Methodology.

~~**R1.**~~**R3.** The ~~Planning Authority~~Transmission Operator shall ~~establish SOLs, including IROLs, for~~provide its ~~Planning Authority Area that are consistent~~SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

M3. ~~The Transmission Planner shall establish SOLs, including IROLs, for its~~Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Transmission ~~Planning Area that are consistent~~Operator provided its SOLs in accordance with its ~~Planning Authority's~~Reliability Coordinator's SOL Methodology.

~~**R1.** The Reliability Coordinator, Planning Authority, and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows:~~

R4. ~~The~~Each Reliability Coordinator shall ~~provide its SOLs~~establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator established stability limits in accordance with Requirement R4.

R5. Each Reliability Coordinator shall provide: *[Violation Risk Factor: High] [Time Horizon: Operations Planning, Same-day Operations, Real-Time Operations]*

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) ~~to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and~~ at least once every twelve calendar months.

~~**1.1.**~~**5.2.** Each impacted Planning ~~Authorities~~Coordinator within its Reliability Coordinator Area~~. For~~, the following information for each established stability limit and each established IROL~~, the Reliability Coordinator shall provide the following supporting information~~ at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

~~**1.1.1.**~~**5.2.2.** Identification ~~and status~~ of the ~~associated Facility (or group of~~ Facilities~~)~~ that ~~is (~~are~~)~~ critical to the derivation of the stability limit or IROL~~.~~;

~~**1.1.2.**~~**5.2.3.** The ~~value of the IROL and its~~ associated IROL T_V~~.~~ for any IROL;

~~**1.1.3.**~~**5.2.4.** The associated Contingency(ies~~).~~); and

~~**1.1.4.**~~**5.2.5.** The type of limitation represented by the stability limit or IROL (*e.g.*, voltage collapse, angular stability).

5.3. ~~The~~Each impacted Transmission Operator ~~shall provide any SOLs it developed~~within its Reliability Coordinator Area, the value of the stability limits established pursuant to ~~its Reliability Coordinator~~Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame

necessary for inclusion in the Transmission ~~Service Providers that share its portion of the~~ Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

~~1.2.~~5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

~~**R1.1.** The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators and Reliability Coordinators that work within its Planning Authority Area.~~

~~**R1.2.** The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.~~

~~**R2.** The Planning Authority shall identify the subset of multiple contingencies (if any), from Reliability Standard TPL-003 which result in stability limits.~~

~~**R2.1.** The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits.~~

~~**R2.2.** If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the~~ Each requesting Transmission Operator within its Reliability Coordinator~~.~~

~~A. Measures~~

5.5. ~~The~~ Area, requested SOL information for its Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each be able~~ Area, on a mutually agreed upon schedule.

~~**M4.**~~ Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that ~~it developed its SOLs (including the subset of SOLs that are IROLs) consistent with the applicable SOL Methodology in accordance with Requirements 1 through 4.~~

~~**M5.** The~~ the Reliability Coordinator~~, Planning Authority, Transmission Operator, and Transmission Planner shall each have evidence that its SOLs (including the subset of SOLs that are IROLs) were supplied in accordance with schedules supplied by the requestors of such SOLs as specified in Requirement 5.~~

~~**M6.**~~**M5.** ~~The Planning Authority shall have evidence it identified a list of multiple contingencies (if any) and their associated stability limits and~~ provided the ~~list and the limits to its Reliability Coordinators~~information in accordance with Requirement ~~6~~R5.

R6. Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the Reliability Coordinator provided the list of Facilities in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

~~**2.1. Compliance Monitoring Responsibility**~~

~~Regional Reliability Organization~~

~~**2.2. Compliance Monitoring Period and Reset Time Frame**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each verify compliance through self-certification submitted to its Compliance Monitor annually. The Compliance Monitor may conduct a targeted audit once in each calendar year (January – December) and an investigation upon a complaint to assess performance.~~

~~The Performance-Reset Period shall be twelve months from the last finding of non-compliance.~~

~~**2.3. Data Retention**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each keep documentation for 12 months. In addition, entities found non-compliant shall keep information related to non-compliance until found compliant.~~

~~The Compliance Monitor shall keep the last audit and all subsequent compliance records.~~

~~**2.4. Additional Compliance Information**~~

~~The Reliability Coordinator, Planning Authority, Transmission Operator, and Transmission Planner shall each make the following available for inspection during a targeted audit by the Compliance Monitor or within 15 business days of a request as part of an investigation upon complaint:~~

~~**2.4.1** SOL Methodology(ies)~~

~~**2.4.2** SOLs, including the subset of SOLs that are IROLs and the IROLs supporting information~~

~~**2.4.3** Evidence that SOLs were distributed~~

~~**2.4.4** Evidence that a list of stability-related multiple contingencies and their associated limits were distributed~~

~~**2.4.5** Distribution schedules provided by entities that requested SOLs~~

1.1. Compliance Enforcement Authority:

"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:

The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Reliability Coordinator or Transmission Operator shall keep data or evidence of Requirements R1 through R6 for the current year plus the previous 12 calendar months.

1.3. Compliance Monitoring and Enforcement Program

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels~~:~~

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	~~There are SOLs, for the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs, for the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R1)~~N/A	~~There are SOLs~~The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for ~~the~~its Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Reliability Coordinator's~~ its System Operating Limit Methodology ("SOL Methodology~~. (R1)~~") as established in FAC-011-4.
R2.	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but from 1% up to but less than 25% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	~~The Transmission Operator has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Reliability Coordinator's SOL Methodology. (R2)~~N/A	The Transmission Operator ~~has established~~did not establish SOLs for its portion of the Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the~~its Reliability Coordinator's SOL Methodology~~. (R2)~~
R3.	~~There are SOLs, for the Planning Coordinator Area, but from 1% up to, but less than,~~	~~There are SOLs, for the Planning Coordinator Area, but 25% or more, but less than 50%~~	~~There are~~The Transmission Operator provided its SOLs	~~There are SOLs, for the Planning Coordinator Area, but 75% or more of these SOLs are~~

	~~25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~N/A	~~for the Planning~~to its Reliability Coordinator ~~Area~~, but ~~50% or more, but less than 75% of these~~did not provide its SOLs ~~are inconsistent with~~at the periodicity at which the ~~Planning Coordinator's SOL Methodology. (R3)~~RC needs such information to perform its reliability functions.	~~inconsistent with the Planning Coordinator's SOL Methodology. (R3)~~The Transmission Operator did not provide its SOLs to its Reliability Coordinator.
R4.	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but up to 25% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Planning Coordinator Area, but 25% or more, but less than 50% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	~~The Transmission Planner has established SOLs for its portion of the Reliability Coordinator Area, but 50% or more, but less than 75% of these SOLs are inconsistent with the Planning Coordinator's SOL Methodology. (R4)~~N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission ~~Planner has established SOLs for~~Operator in its ~~portion of the Planning~~Reliability Coordinator Area~~, but 75% or more of these SOLs are inconsistent~~ in accordance with ~~the Planning Coordinator's~~its SOL Methodology. ~~(R4)~~
R5 ~~.~~	~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all the requesting entities but missed meeting one or more of the schedules by less than 15 calendar days. (R5)~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but one of the requesting~~	~~One of the following:~~ ~~The responsible entity provided its SOLs (including the subset of SOLs that are IROLs) to all but two of the requesting~~	~~One of the following:~~ ~~The responsible entity failed to provide its SOLs (including the subset of SOLs that are IROLs) to more than two of the requesting entities within 45~~

	The Reliability Coordinator did not provide one of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 15 or more but less than 30 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.4~~ The Reliability Coordinator did not provide two of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~entities within the schedules provided. (R5)~~ ~~Or~~ ~~The responsible entity provided its SOLs to all the requesting entities but missed meeting one or more of the schedules for 30 or more but less than 45 calendar days. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.3~~ The Reliability Coordinator did not provide three of the items listed in Requirement R5, Parts 5.1 through 5.5.	~~calendar days of the associated schedules. (R5)~~ ~~OR~~ ~~The supporting information provided with the IROLs does not address 5.1.1 and 5.1.2.~~ The Reliability Coordinator did not provide four or more of the items listed in Requirement R5, Parts 5.1 through 5.5.
R6 ~~:~~	~~The Planning Authority failed to notify the Reliability Coordinator in accordance with R6.2~~N/A	~~Not applicable.~~N/A	~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~ N/A	~~The Planning Authority did not identify the subset of multiple contingencies which result in stability limits. (R6)~~ ~~OR~~ ~~The Planning Authority identified the subset of multiple contingencies which result in stability limits **but** did not provide the list of multiple contingencies and associated limits to more than one Reliability Coordinator that monitors the Facilities associated with these limits. (R6.1)~~The Reliability Coordinator with an established IROL, or the

				Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

D. Regional ~~Differences~~Variances

None ~~identified.~~

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1	November 1, 2006	Adopted by Board of Trustees	New
2		Changed the effective date to January 1, 2009 Replaced Levels of Non-compliance with Violation Severity Levels	Revised
2	June 24, 2008	Adopted by Board of Trustees: FERC Order	Revised
2	January 22, 2010	Updated effective date and footer to April 29, 2009 based on the March 20, 2009 FERC Order	Update
2	April 29, 2015 – July 23, 2015	Incorrectly included TOP as the applicable function for Requirement R5. 7/23/15: Corrected to designate R5 as: RC, PA and TP.	Revised
3		Project 2015-09 Adopt revised standard.	Revision

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Mapping Document for FAC-014-2

Project 2015-09 Establish and Communicate System Operating Limits

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
FAC-014-2, Requirement R1 R1. The Reliability Coordinator shall ensure that SOLs, including Interconnection Reliability Operating Limits (IROLs), for its Reliability Coordinator Area are established and that the SOLs (including Interconnection Reliability Operating Limits) are consistent with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (SOL Methodology). R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology. R4. Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.	Requirements R1, R2, and R4 of FAC-014-3 ensure that SOLs are established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. Requirement R1 was changed to address an issue with the existing language in FAC-014-2, Requirement R1. With the original language, the RC is responsible for ensuring that SOLs established by the Transmission Operator (TOP) per FAC-014-2, Requirement R2 are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP. Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
		not ensure that the TOP's SOL was consistent with its SOL Methodology. The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area. FAC-011-4 requirement R4 further addresses the RC responsibilities (beyond IROL establishment) for stability limit establishment where more than one TOP is impacted.
FAC-014-2, Requirement R2 R2. The Transmission Operator shall establish SOLs (as directed by its Reliability Coordinator) for its portion of the Reliability	FAC-014-3, Requirement R2 R2. Each Transmission Operator shall establish System Operating Limits (SOLs) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.	The language from the existing FAC-014-2, Requirement R2 that states the TOP, "(as directed by its Reliability Coordinator)" was removed because it causes confusion and may be incorrectly understood to mean that the TOPs are

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
Coordinator Area that are consistent with its Reliability Coordinator's SOL Methodology.		only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the drafting team has removed the unnecessary and potentially confusing language. The proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.
FAC-014-2, Requirements R3 and R4 R3. The Planning Authority shall establish SOLs, including IROLs, for its Planning Authority Area that are consistent with its SOL Methodology. R4. The Transmission Planner shall establish SOLs, including IROLs, for its Transmission Planning Area that are consistent with its Planning Authority's SOL Methodology.	1. FAC-011-4, Requirement R8, Part 8.2 2. FAC-015-1, Requirements R 1 – R6 FAC-011-4, Requirement R8, Part 8.2: R8. Each Reliability Coordinator shall provide its new or revised SOL Methodology to: 8.2. Each Planning Coordinator and Transmission Planner responsible for planning any portion of the Reliability Coordinator Area prior to the effective date of the SOL Methodology;	The PCs and TOPs responsible for planning any portion of the RC's Area are made aware of the RC's SOL Methodology through FAC-011-4, Requirement R8, Part 8.2. By having the RC's SOL Methodology, PCs and TPs who plan any portion of the System in the RC Area have knowledge of the methods and criteria for establishing SOLs, including the stability performance criteria used for establishing stability limits in the operations horizon. New Reliability Standard FAC-015-1 along with the changes made to FAC-011-4 and FAC-014-3 represent an improvement for

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	FAC-015-1: R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its	planning and operations to better work together to address the reliability issues that are ultimately faced in Real-time operations. FAC-015-1, Requirements R1 – R3 ensures that Planning Assessments performed for the Near-Term Transmission Planning Horizon (required by TPL-001-4), are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R1 addresses Facility Ratings used in Planning Assessments, Requirement R2 addresses the System steady state voltage limits used in Planning Assessments, and Requirement R3 addresses the stability performance criteria used in Planning Assessments. These requirements address the three components of SOLs used in operations and facilitates continuity between operations and planning.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more	Implementing the processes required in FAC-015-1, Requirements R1 – R3 provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 requires the PC to provide those Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its TPs and to requesting PCs. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. By implementing Requirements R1 – R5 of FAC-015-1, equally limiting or more limiting Facility Ratings, System steady-

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-	state voltage limits and stability criteria that are established in accordance with the RC's SOL Methodology are ultimately implemented in the Planning Assessments performed by the PCs and TPs, thus improving reliability by ensuring continuity between planning and operations. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	
<u>FAC-014-2, Requirement R5, R5.1</u> R5. The Reliability Coordinator, Planning Authority and Transmission Planner shall each provide its SOLs and IROLs to those entities that have a reliability-related need for those limits and provide a written request that includes a schedule for delivery of those limits as follows: R5.1. The Reliability Coordinator shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Reliability Coordinators and Reliability Coordinators who indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, Transmission Service Providers and Planning Authorities within its Reliability Coordinator Area. For each IROL, the Reliability Coordinator shall provide the following supporting information:	The communication of SOL and IROL information from the Reliability Coordinator is addressed by: 1. FAC-014-3, Requirement R5 (addresses communication from the Reliability Coordinator to other entities) 2. IRO-014-3, Requirement R1 (addresses communication between Reliability Coordinators to support reliable operations) <u>FAC-014-3, Requirement R5:</u> R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area, the following	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. While the existing requirements in FAC-014-2, Requirement R5 are preserved in FAC-014-3, Requirement R5, FAC-014-3, Requirement R5 more specifically address the communications requirements for the RC. Each recipient of the RC communications is addressed in a separate subpart because each recipient has a slightly different need. This approach represents an improvement over the former approach. IRO-014-3, Requirement R1 and subparts addresses RC communication of critical operational information to adjacent RCs,

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
R5.1.1. Identification and status of the associated Facility (or group of Facilities) that is (are) critical to the derivation of the IROL. R5.1.2. The value of the IROL and its associated Tv. R5.1.3. The associated Contingency(ies). R5.1.4. The type of limitation represented by the IROL (e.g., voltage collapse, angular stability).	information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). 5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. 5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the	which addresses RC-to-RC communication and coordinated operations issues.

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses. 5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule. <u>IRO-014-3, Requirement R1</u> R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following: 1.1. Criteria and processes for notifications. 1.2. Energy and capacity shortages.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	1.3. Control of voltage, including the coordination of reactive resources. 1.4. Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments. 1.5. Provisions for periodic communications to support reliable operations.	
FAC-014-2, Requirement R5, R5.2 R5.2 The Transmission Operator shall provide any SOLs it developed to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	1. FAC-014-3, Requirement R3 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2.6 FAC-014-3, Requirement R3 R3. The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than:	The communication of SOLs from the TOP to its RC is preserved in FAC-014-3, Requirement R3. The revised language represents an improvement on the current standard because the specifics of TOP communication to the RC is now addressed in the RC's SOL Methodology. This revised requirement has a companion Requirement R7 in FAC-011-4 which states: R7. Each Reliability Coordinator shall include in its SOL Methodology the method and periodicity for Transmission Operators to communicate SOLs it established to its RC(s).

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path. MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment.	The Transmission Service Provider (TSP) was removed from the SOL communication chain because the TSP does not need SOLs to perform its obligations specified in the Modeling, Data, and Analysis (MOD) standards; rather, they need Total Transfer Capability (TTC) and Total Flowgate Capability (TFC) from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs.
FAC-014-2, Requirement R5, R5.3 and R5.4 R5.3 The Planning Authority shall provide its SOLs (including the subset of SOLs that are IROLs) to adjacent Planning Authorities, and to Transmission Planners, Transmission Service Providers, Transmission Operators	1. FAC-015-1, Requirements R1 – R6 2. MOD-028-2, Requirement R7 3. MOD-029-2a, Requirement R4 4. MOD-030-3, Requirement R2 5. TPL-001-4, Requirement R8 FAC-015-1, Requirements R1 –R6:	Reference the description above for Requirement R3 which describes a different set of roles and responsibilities for the PC and TP as defined in FAC-015-1. Implementing the processes required in FAC-015-1, Requirements R1 – R3

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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and Reliability Coordinators that work within its Planning Authority Area. R5.4 The Transmission Planner shall provide its SOLs (including the subset of SOLs that are IROLs) to its Planning Authority, Reliability Coordinators, Transmission Operators, and Transmission Service Providers that work within its Transmission Planning Area and to adjacent Transmission Planners.	R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the	provides the PC with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R4 addresses the PC's role for providing the Facility Ratings, System steady-state voltage limits and stability performance criteria derived from Requirements R1 – R3 to the TPs and to requesting PCs for their use in performing Planning Assessments. FAC-015-1, Requirement R5 requires the TP to use the Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its PC. FAC-015-1, Requirements R1 – R5 result in PC and TPs using Facility Ratings, System steady state voltage limits, and stability performance criteria in their

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	Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators. R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-	Planning Assessments that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the RC's SOL Methodology. FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation identified in the Planning Assessments to the RC and to impacted TOPs. The subparts of Requirement R6 require the communication of key information that can be useful to the RC and TOP to establish stability limits and IROLs that will ultimately be used in real-time operations. The TSP was removed from the SOL communication chain. The TSP does not need SOLs from the PCs or TPs; rather, TSPs need TTC and TFC from the TOPs as required in Requirement R7 of MOD-028-2, Requirement R4 of MOD-029-2a, and Requirement R2.6 of MOD-030-3. The

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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	state voltage limits, and stability criteria provided by its Planning Coordinator. R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;	TTCs and TFCs provided to the TSPs already reflect the impact of any SOLs. TPL-001-4, Requirement R8 requires each PC and TP to distribute its Planning Assessment results to adjacent PCs and adjacent TPs within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. With this requirement, any functional entity with a reliability-related need for a PC's or TP's Planning Assessment can obtain that Planning Assessment. Requesting entities are then made aware of any system performance issues identified by these Planning Assessments.

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	6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation. MOD-028-2, Requirement R7: R7. The Transmission Operator shall provide the Transmission Service Provider of that ATC Path with the most current value for TTC for that ATC Path no more than: R7.1. One calendar day after its determination for TTCs used in hourly and daily ATC calculations. R7.2. Seven calendar days after its determination for TTCs used in monthly ATC calculations. MOD-029-2a, Requirement R4: R4. Within seven calendar days of the finalization of the study report, the Transmission Operator shall make available to the Transmission Service Provider of the ATC Path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that ATC Path.	

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	MOD-030-3, Requirement R2.6: [The TOP shall…] R2.6. Provide the Transmission Service Provider with the TFCs within seven calendar days of their establishment. TPL-001-4, Requirement R8: R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. 8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
FAC-014-2, Requirement R6 R6. The Planning Authority shall identify the subset of multiple contingencies (if any),	FAC-015-1, Requirement R6 R6. Each Planning Coordinator shall communicate any instability, Cascading or	FAC-015-1, Requirement R6 cover the content of FAC-014-2, Requirement R6 and improves upon it as follows:

Standard: FAC-014-2 Establish and Communicate System Operating Limits		
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from Reliability Standard TPL-003 which result in stability limits. R6.1 The Planning Authority shall provide this list of multiple contingencies and the associated stability limits to the Reliability Coordinators that monitor the facilities associated with these contingencies and limits. R6.2 If the Planning Authority does not identify any stability-related multiple contingencies, the Planning Authority shall so notify the Reliability Coordinator.	uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This communication shall include: 6.1 The type of the instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation); 6.2 The associated stability criteria used as part of determining the instability; 6.3 The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation; 6.4 Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; 6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.	• FAC-015-1, Requirement R6 addresses not only the identification of multiple contingencies that result in stability limits, but also address the key information RCs need to establish stability limits and IROLs used in operations. Unlike FAC-014-2, Requirement R6, FAC-015-1, Requirement R6 ensures the type of instability, relevant stability criteria, and mitigation assumptions used by the PC are communicated to the appropriate RC. • Additionally, FAC-015-1, Requirement R6 includes all planning events (single and multiple contingencies) that result in instability, Cascading, or uncontrolled separation. • FAC-014-2, Requirement R6, R6.2 is addressed by FAC-015-1, Requirement R6 because all instances of instability identified by the PC are to be communicated

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		to the RC in accordance with FAC-015-1, Requirement R6. In addition, FAC-014-2, Requirement R6, R6.2 is administrative in nature, given that the existing FAC-014-2, Requirement R6, R6.1 and proposed FAC-015-1, Requirement R6 both require communication of a defined set of stability related data. The absence of any communication of stability related data inherently implies the PC has not identified any instability and therefore has nothing to communicate.

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Rationales for FAC-014-3

September 2017

Requirement R1

Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit methodology (SOL Methodology).

Rationale R1

Reliability Standard FAC-014-2 Requirement R1 requires that the Reliability Coordinator (RC) ensure that System Operating Limits (SOLs), including Interconnection Reliability Operating Limits (IROLs), for its RC Area are established and that the SOLs (including IROLs) are consistent with its SOL Methodology.

Furthermore, Requirement R2 of FAC-014-2 requires the Transmission Operator (TOP) to establish SOLs consistent with its RC's SOL Methodology.

Under this structure the RC is responsible for ensuring that SOLs established by the TOP, per Requirement R2, are consistent with the RC's SOL Methodology. This creates a situation where the RC is responsible for "ensuring" the actions of the TOP.

Accordingly, if the TOP does not establish SOLs per its RC's SOL Methodology, then 1) the TOP is in violation of Requirement R2, and 2) the RC by default is in violation of Requirement R1 because the RC did not ensure that the TOP's SOL was consistent with its SOL Methodology.

The proposed revision addresses this issue and clarifies the appropriate responsibilities of the respective functional entities. Additionally, this requirement carries forward the obligation of the RC to establish IROLs for its RC Area. The RC maintains primary responsibility for establishment of IROLs because these limits have the potential to impact a Wide-area.

Requirement R2

Each Transmission Operator shall establish System Operating Limits (SOL) for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R2

Requirement R2 preserves the intent of Requirement R2 of FAC-014-2.

The standard drafting team (SDT) removed language from the existing FAC-014-2 Requirement R2 that states the TOP "shall establish SOLs (as directed by its Reliability Coordinator)" because it causes confusion and may be incorrectly understood to mean that the TOPs are only required to establish SOLs if they have been "directed to by their RC." This is not the intended meaning of the requirement, thus, the SDT has removed the unnecessary and potentially confusing language. The

proposed language makes clear that the TOP is the entity responsible for establishing SOLs, and that these SOLs must be established in accordance with the RC's SOL Methodology.

Requirement R3

The Transmission Operator shall provide its SOLs to its Reliability Coordinator in accordance with its Reliability Coordinator's SOL Methodology.

Rationale R3

Requirement R3 requires TOPs to provide the SOLs it established (under requirement R2) to the RC in accordance with the RC's SOL Methodology. This requirement is a companion requirement to FAC-011-4 Requirement R7, which states: "Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to communicate SOLs it established to its RC(s). The method shall address the periodicity of SOL communication." These two requirements work together to ensure that SOLs established by the TOP in accordance with the RC's SOL Methodology are communicated to the RC in a timely manner.

The SDT recognizes that the provision of SOL information from the TOP to the RC may also be addressed via IRO-010-2, but the proposed requirement may also be utilized for SOL information other than what is utilized for Operational Planning Analysis (OPA)/ Real-time Assessment (RTA)/ Real-time monitoring. In such instances, the timing requirements should be coordinated between the RC's SOL methodology and the data specification document.

Requirement R4

Each Reliability Coordinator shall establish stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

Rationale R4

Requirement R4 requires that the RC establish stability limits to be used in operations when the limit impacts more than one TOP in its RC Area. This ensures that the RC who has wide-area responsibility will identify such stability limits and prevent any gaps in identification and monitoring of stability limits that impacts more than one TOP in its RC Area. TOPs are still required to identify stability limits that are within its TOP area (including Generator Operator areas interconnected to its TOP area).

Requirement R5

Each Reliability Coordinator shall provide:

5.1. Each Planning Coordinator within its Reliability Coordinator Area, SOLs for its Reliability Coordinator Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months.

5.2. Each impacted Planning Coordinator within its Reliability Coordinator Area,, the following information for each established stability limit and each established IROL at least once every twelve calendar months:

5.2.1. The value of the stability limit or IROL;

5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL;

5.2.3. The associated IROL T_v for any IROL;

5.2.4. The associated Contingency(ies); and,

5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability).

5.3. Each impacted Transmission Operator within its Reliability Coordinator Area, the value of the stability limits established pursuant to Requirement R4 and each IROL established pursuant to Requirement R1, in an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analysis, Real-time monitoring, and Real-time Assessments.

5.4. Each impacted Transmission Operator within its Reliability Coordinator Area, the information identified in Requirement R5 Parts 5.2.2 – 5.2.5 for each established stability limit or each IROL, and any updates to that information within an agreed upon time frame necessary for inclusion in the Transmission Operator's Operational Planning Analyses.

5.5. Each requesting Transmission Operator within its Reliability Coordinator Area, requested SOL information for its Reliability Coordinator Area, on a mutually agreed upon schedule.

Rationale R5

Requirement R5 requires the RC to provide SOLs (including the subset that are IROLs) and any updates to those SOLs to Planning Coordinators (PCs) and Transmission Operators (TOP)s. This is an improvement over Requirement R5 in FAC-014-2 because it provides additional clarity on when the RC is responsible for performing these tasks. FAC-014-2 Requirement R5 includes the triggering clause of when entities "provide a written request that includes a schedule for delivery of those limits", while Requirement R5 of FAC-014-3 clearly identifies the RC's responsibilities with or without a request. This also removes confusion associated with FAC-010 in terms of SOLs existing in the planning horizon. All requirements in pertaining to SOLs in the planning horizon have thus been removed.

The requirement addresses varying needs in terms of both the content and the frequency at which the information is provided. This requirement also complements existing NERC requirements that provide a construct for communication of SOLs and SOL-related information (e.g. TOP-003-3, IRO-010-2, IRO-014-3) to prevent redundancies in requirements. TOP-to-TOP SOL information communication is addressed in TOP-003-3. RC-to-RC SOL information communication is addressed

in IRO-014-3. TOP-to-RC information communication is addressed in Requirement R3 and may be addressed in IRO-010-2.

Requirement R5 Part 5.1 requires the RC to provide the PCs in its RC Area all SOLs and relevant SOL information at least once every 12 calendar months. This provides the PC the relevant information necessary for its assessments and its Transmission Planner's (TP's) assessments. MOD-032-1 and FAC-015-1 requirements provides the mechanism for SOLs to be communicated between the PCs and its TPs. It is expected that PCs do not need more frequent updates as most of their assessments are performed on an annual cycle. Transmission Service Providers were not retained as an entity that would have a reliability related need for stability limit and IROL related information. Nothing prohibits an RC from sharing such information outside of a NERC Reliability Standard for other non-reliability related purposes.

Requirement R5 Part 5.2 requires the RC to provide the impacted PCs additional specific information (consistent with FAC-014-2 R5.1.1 - R5.1.4) for stability limits and IROLs at least once every 12 calendar months. It is expected that PCs do not need more frequent updates as most of their assessments (and their respective TPs assessments) are performed on an annual cycle.

Requirement R5 Part 5.3 requires the RC to provide the impacted TOPs within its RC Area the value of the stability limits established in Requirement R4 and IROLs established in Requirement R1 in the Real-time Operations time horizon. This recognizes that the actual numerical "limit" (whether a new limit or modification of an existing one) may change based on varying system topology and thus those limit values must be provided in a timeframe designed to meet the impacted TOP's needs for their OPA, Real-time monitoring, and RTA.

Requirement R5 Part 5.4 requires the RC to provide the impacted TOPs additional specific information (consistent with FAC-014-2 R5.1.1-5.1.4) for stability limits and IROLs within Same-day or Operations Planning time horizon. This additional information is essential for the TOP's OPA; however, it can be communicated within a longer-term agreed upon time frame outside the Real-time Operations time horizon.

Additionally, Requirement R5 Part 5.5 requires that if a TOP requests any SOL information beyond what impacts that TOP, the RC must provide this SOL information as well. Both Requirement R5 Parts 5.4 and 5.5 require that the related information be provided in a mutually agreed upon schedule to ensure the TOP's needs are met (e.g. OPA, RTA, etc.) and the RC's ability to meet those needs are taken into consideration.

Requirement R6

Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

Rationale R6

Requirement R6 addresses FERC Order No. 777 directive for the communication of IROL information to Transmission Owners (TOs) (P6 and P41). FERC Order No. 777 states:

> *"As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC should establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners...One way to achieve this objective...is to modify FAC-014 to require the provision of IROLs to transmission owners. However, we leave it to NERC to determine the most appropriate means for communicating IROL status to transmission owners." (P 41)*

Requirement R5 Parts 5.2.1 through 5.2.5 requires that IROL information – including the Facilities critical to the derivation of the IROL – be communicated to the TOPs. SDT determined that while TOs and Generator Owners (GOs) need to be made aware of their Facilities that are critical to the derivation of the IROL, the TOs and GOs do not need to know the other IROL information specified in Requirement R5 Part 5.2.1 and Parts 5.2.3 through 5.2.5. These items may contain operationally sensitive information that should be limited to the TOPs that operate the equipment. Therefore, the SDT separated the communication to the TOs and GOs into a stand-alone Requirement R6.

The language "Each Reliability Coordinator that is impacted by an IROL" was used to cover scenarios where an IROL in one Reliability Coordinator Area contains Facilities that reside in a neighboring Reliability Coordinator's Area that are critical to the derivation of the IROL. Therefore, any Facilities that are critical to the derivation of an IROL will be communicated from the responsible RC to the appropriate TOs and GOs.

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Violation Risk Factor and Violation Severity Level Justifications

FAC-014-3 Establish and Communicate System Operating Limits

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-014-3 Establish and Communicate System Operating Limits (SOLs). Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-014-3 Requirement R1	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failing to correctly identify an IROL could directly cause or contribute to Bulk Electric System (BES) instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area in accordance with its System Operating Limit Methodology (“SOL Methodology”) as established in FAC-011-4.

VSL Justifications for FAC-014-3, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R2 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Operator did not establish SOLs for its portion of the Reliability Coordinator Area in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.2 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-014-3, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Transmission Operator provided its SOLs to its Reliability Coordinator, but did not provide its SOLs at the periodicity at which the RC needs such information to perform its reliability functions.	The Transmission Operator did not provide its SOLs to its Reliability Coordinator.

VSL Justifications for FAC-014-3, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.2 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R4	
Proposed VRF	**High**
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	The VRF is consistent with the conclusions of the final Blackout Report.
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	The requirement has no sub-requirements so a single VRF was assigned.
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	A VRF of high for this requirement is consistent with approved Reliability Standard TPL-001-4 which requires development of operating conditions through the use of system models.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	The establishment of incorrect stability limits could directly cause or contribute to BES instability, separation, or a cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	The requirement contains one objective, therefore a single VRF is assigned.

VSLs for FAC-014-3, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator did not determine stability limits to be used in operations when the limit impacts more than one Transmission Operator in its Reliability Coordinator Area in accordance with its SOL Methodology.

VSL Justifications for FAC-014-3, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R5	
Proposed VRF	**High**

This reliability objective of Requirement R5 and Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator did not provide one of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide two of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide three of the items listed in Requirement R5 Parts 5.1 through 5.5.	The Reliability Coordinator did not provide four or more of the items listed in Parts 5.1 through 5.5.

VSL Justifications for FAC-014-3, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, sub-requirement R5.1. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-014-3 Requirement R6	
Proposed VRF	**High**

This reliability objective of Requirement R5, R5.1 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-014-3. Therefore, the existing VRF of high was maintained for consistency.

VSLs for FAC-014-3, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Reliability Coordinator with an established IROL, or the Reliability Coordinator impacted by a neighboring Reliability Coordinator IROL, did not provide Transmission Owners or Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL.

VSL Justifications for FAC-014-3, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	08/19/15
SAR posted for comment	08/20/15 – 09/21/15

Anticipated Actions	Date
45-day formal comment period with ballot	September 2017 – November 2017
45-day formal comment period with additional ballot	January 2018 – February 2018
10-day final ballot	February 2018
NERC Board adoption	May 2018

A. Introduction

1. **Title:** Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

2. **Number:** FAC-015-1

3. **Purpose:** To ensure the Facility Ratings, System steady-state voltage limits, and stability criteria used in Planning Assessments are coordinated with the Reliability Coordinator's System Operating Limits (SOL) Methodology.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Planning Coordinator

   4.1.2. Transmission Planner

5. **Effective Date:** See Implementation Plan for Project 2015-09.

B. Requirements and Measures

R1. Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R1.

R2. Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R2.

R3. Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL Methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator implemented its process in accordance with Requirement R3.

R4. Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinator's. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator provided its information in accordance with Requirement R4.

R5. Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Transmission Planner used the information provided by its Planning Coordinator in accordance with Requirement R5.

R6. Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- **6.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- **6.2** The associated stability criteria used as part of determining the instability;
- **6.3** The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
- **6.4** Any Remedial Action Scheme action, undervoltage load shedding (UVLS) action, underfrequency load shedding (UFLS) action, interruption of Firm Transmission

Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation; and

6.5 Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

M6. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation demonstrating the Planning Coordinator communicated the information in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
"Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator and Transmission Planner shall keep evidence for Requirements R1 through R6 for the most current year plus the previous three years.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.
R2.	N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.
R3.	N/A	The Planning Coordinator used less limiting stability	The Planning Coordinator used less limiting stability	The Planning Coordinator failed to implement a

		performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in the Reliability Coordinator's SOL Methodology.
R4.	N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.
R5.	N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

R6.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator, but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

D. Regional Variances

None

E. Interpretations

None

F. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
1		Project 2015-09 SOL – Adopt new standard.	New

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Rationale for FAC-015-1

September 2017

Requirement R1

Each Planning Coordinator, when developing its steady-state modeling data requirements, shall implement a process to ensure that Facility Ratings used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than those established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R1

Requirement R1 was drafted to ensure the appropriate use of applicable Facility Ratings in planning models. Analysis of these models determines System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operations. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Requirement R1 provides a mechanism for the coordination of Facility Ratings in planning models to those established in accordance with the Reliability Coordinator's (RC's) System Operating Limit (SOL) Methodology. Since the analysis of planning models determines what facilities are constructed or modified, Facility Ratings used in these analyses should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by thermal constraints that were not identified in preceding planning studies.

Reliability Standard MOD-032 requires the modeling data in a Planning Coordinator (PC) area be coordinated between the PC and applicable Transmission Planners (TPs). It is the opinion of the standard drafting team (SDT) that the resulting coordination is the appropriate means to ensure Facility Ratings included in planning models are equally limiting or more limiting than the Facility Ratings established in accordance with the RC's SOL Methodology, since Planning Assessments and Corrective Action Plans are developed based on analysis of these models (TPL-001).

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R1 is not to change, limit, or modify Facility Ratings determined by the equipment owner per FAC-008. The intent is to utilize those owner-provided Facility Ratings such that the System is planned to support the reliable operation of that System. This is accomplished by requiring the PC to use Facility Ratings that are equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. If less limiting Facility Ratings are used by the PC, a technical justification is required to be documented and provided to the RC. This does

not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R2

Each Planning Coordinator shall implement a process to ensure that System steady state voltage limits used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology. If the Planning Coordinator uses less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R2

The purpose of TPL-001 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001, planning criteria used in developing the Planning Assessment should support the eventual operation of BES Facilities.

Requirement R2 was drafted to ensure the use of appropriate System steady-state voltage limits when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what Facilities are constructed or modified, the application of System steady-state voltage limits used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than those established in accordance with the RC's SOL Methodology. Otherwise, operators could be unduly limited by voltage constraints that were not identified in preceding planning studies. Requirement R2 provides a mechanism for the coordination of System steady-state voltage limits evaluated in planning studies with the System Voltage Limits established in accordance with the RC's SOL Methodology.

The Near-Term Transmission Planning Horizon is specified because planning assumptions tend to be more certain earlier in the planning horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.
The intent of Requirement R2 is to supplement Requirement R5 of TPL-001-4 which states, "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level

and a maximum length of time that transient voltages may remain below that level." When determining the criteria for System steady-state voltage limits in accordance with TPL-001-4 Requirement R2, the PC is required to implement the process described in FAC-015-1 Requirement R2.

Requirement R2 requires the PC to use System steady-state voltage limits that are equally limiting or more limiting than the System Voltage Limits established in accordance with the RC's SOL methodology. If less limiting System steady-state voltage limits are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R3

Each Planning Coordinator shall implement a process to ensure the stability performance criteria used in its Planning Assessment of the Near-Term Transmission Planning Horizon are equally limiting or more limiting than the stability performance criteria established in its Reliability Coordinator's SOL methodology. If the Planning Coordinator uses less limiting stability performance criteria than the stability performance criteria specified in its Reliability Coordinator's SOL methodology, the Planning Coordinator shall provide a technical justification to its Reliability Coordinator.

Rationale R3

The purpose of TPL-001-4 is to "…develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probably Contingencies." Because the Planning Assessment (including the Corrective Action Plan) is the primary output of TPL-001-4, planning criteria used in developing the Planning Assessment should support the eventual operation of BES facilities.

Requirement R3 was drafted to ensure the use of appropriate stability performance criteria when performing studies in support of developing the Planning Assessment. These studies determine System needs, potential future transmission expansion and other Corrective Action Plans for reliable System operation. Therefore, it is imperative that the System is planned in such a way to support the successful operation of facilities when they are placed in service.

Since the analysis of planning models determines what facilities are constructed or modified, the application of stability performance criteria used in studies that support the development of the Planning Assessment should be equally limiting or more limiting than the criteria specified in the RCs SOL Methodology. Otherwise, operators could be unduly limited by stability constraints that were not identified in preceding planning studies. Requirement R3 provides a mechanism for the coordination of stability performance criteria evaluated in planning studies with the Reliability Coordinator's SOL Methodology.

The Near-Term Planning Horizon is specified because planning assumptions tend to be more certain earlier in the Planning Horizon. Additionally, construction activities or other Corrective Action Plans are more likely to be finalized in this period.

The intent of Requirement R3 is to address the stability performance criteria used by PCs and TPs when performing the required stability analysis per TPL-001. When the PC performs the relevant stability analyses in accordance with TPL-001, they are required to implement the process in FAC-015-1 Requirement R3, which requires the PC to use stability performance criteria that are equally limiting or more limiting than the criteria established in accordance with the RC's SOL Methodology. If less limiting stability performance criteria are used by the PC, a technical justification is required to be documented and provided to the RC. This does not give the RC authority over the PC in the development of the Planning Assessment. It does, however, facilitate communication between planning and operating entities so that analysis of the System by these entities are coordinated.

Requirement R4

Each Planning Coordinator shall provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in its Planning Assessment to its Transmission Planners and to requesting Planning Coordinators.

Requirement R5

Each Transmission Planner shall use Facility Ratings, System steady-state voltage limits, and stability performance criteria in its Planning Assessment that are equally limiting or more limiting than the Facility Ratings, System steady-state voltage limits, and stability criteria provided by its Planning Coordinator.

Rationale R4 and R5

Requirements R4 and R5 provide for the explicit coordination between PCs and TPs of Facility Ratings, System steady-state voltage limits, and stability performance criteria used to develop Planning Assessments of the PC area. Additionally, Requirement R4 provides a mechanism for other PCs to obtain this same information, as needed. Requirement R5 also allows the TP to use more conservative Facility Ratings, System steady-state voltage limits, and stability performance criteria than those the PC provides where the TP deems appropriate

These requirements supplement TPL-001-4 Requirements R1, R5, and R6 by ensuring Facility Ratings, System steady-state voltage limits, and stability performance criteria are consistently applied in Planning Assessments of the PC area.

Requirement R6

Each Planning Coordinator shall communicate any instability, Cascading or uncontrolled separation identified in either its Planning Assessment of the Near-Term Transmission Planning Horizon or its

Transfer Capability assessment to each impacted Reliability Coordinator and Transmission Operator. This communication shall include:

- **6.1** The type of instability identified (e.g., voltage collapse, angular instability, transient voltage dip criteria violation);
- **6.2** The associated stability criteria used as part of determining the instability;
- **6.3** The associated Contingency(ies) which result(s) in the instability, Cascading or uncontrolled separation;
- **6.4** Any Remedial Action Scheme action, under voltage load shedding (UVLS) action, under frequency load shedding (UFLS) action, interruption of Firm Transmission Service, or Non-Consequential Load Loss required to address the instability, Cascading or uncontrolled separation;
- **6.5** Any Corrective Action Plan associated with the instability, Cascading or uncontrolled separation.

Rationale R6

IRO-017-1 Requirement R3 requires PCs and TPs to provide their Planning Assessments to impacted RCs. However, Requirement R2 Part 2.4 and Requirement R4 in TPL-001-4, which outline the Stability analysis portion of the Planning Assessment, do not provide for the level of detail prescribed in FAC-015-1 Requirement R6. Therefore this requirement was drafted to ensure the appropriate details regarding potential instability identified in the Stability portion of the Planning Assessment for the Near-Term Transmission Planning Horizon are provided to impacted RC and Transmission Operators (TOPs).

The information itemized in Requirement R6 is a key consideration for RC and TOPs in the establishment of SOLs. Of particular importance is the identification of potential risks of instability, Cascading conditions and uncontrolled separation that warrant establishment of an IROL by the RC. The details required by Requirement R6 will supplement the severe System conditions identified Requirements R4 Parts 4.4 & 4.5 of TPL-001-4.

Violation Risk Factor and Violation Severity Level Justifications

FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's SOL Methodology

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard FAC-015-1 System Coordination of Planning Assessments with the Reliability Coordinator's System Operating Limits (SOL) Methodology. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for FAC-015-1 Requirement R1	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R1 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting Facility Ratings than the Facility Ratings established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that Facility Ratings used in Planning Assessment are equally limiting or more limiting than those established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R2	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R2 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting System steady-state voltage limits than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that System steady-state voltage limits used in Planning Assessments are equally limiting or more limiting than the System Voltage Limits established in accordance with its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R3	
Proposed VRF	**Medium**

This reliability objective of Requirement R3 from approved Reliability Standard FAC-014-2 is now Requirement R3 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not provide its documented technical justification to its Reliability Coordinator.	The Planning Coordinator used less limiting stability performance criteria than the stability performance criteria established in its Reliability Coordinator's SOL Methodology, but did not document the technical justification.	The Planning Coordinator failed to implement a process to ensure that stability performance criteria used in planning assessments are equally limiting or more limiting than those used in operations established in its Reliability Coordinator's SOL Methodology.

VSL Justifications for FAC-015-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R4	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 from approved Reliability Standard FAC-014-2 is now Requirement R4 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide one element of the required information.	The Planning Coordinator failed to provide the Facility Ratings, System steady-state voltage limits, and stability performance criteria to all of its Transmission Planners. OR The Planning Coordinator failed to provide two or more elements of the required information.

VSL Justifications for FAC-015-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R5	
Proposed VRF	**Medium**

This reliability objective of Requirement R4 from approved Reliability Standard FAC-014-2 is now Requirement R5 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Transmission Planner failed to use Facility Ratings, System steady-stability voltage limits, and stability performance criteria that were equally or more limiting than those provided by its Planning Coordinator.

VSL Justifications for FAC-015-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R4 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The requirement does not have elements or quantities to evaluate degrees of compliance. The requirement is binary and therefore a VSL of Severe is assigned for non-compliance. The requirement is clear and does not contain any ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

VRF Justifications for FAC-015-1 Requirement R6	
Proposed VRF	**Medium**

This reliability objective of Requirement R5, R5.3 and Requirement R6 from approved Reliability Standard FAC-014-2 is now Requirement R6 of proposed Reliability Standard FAC-015-1. Therefore, the existing VRF of medium was maintained for consistency.

VSLs for FAC-015-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain one of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain two of the elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain three elements listed in Requirement R6, Parts 6.1 – 6.5.	The Planning Coordinator communicated the identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator but the communication did not contain four or more of the elements listed in Requirement R6, Parts 6.1 – 6.5. OR The Planning Coordinator failed to communicate any identified instability, Cascading, or uncontrolled separation to each impacted Reliability Coordinator and Transmission Operator.

VSL Justifications for FAC-015-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement maps to the previously approved Requirement R5, R5.3 and R6 of FAC-014-2. Therefore, the proposed VSLs do not have the unintended consequence of lowering compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is worded consistently with the corresponding requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is not based on a cumulative number of violations.

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Standards Impacted by the Retirement of FAC-010-3

Project 2015-09 Establish and Communicate System Operating Limits

STD	Standard Reference	Comment / Proposed Action
BAL standards		No Action Required
CIP standards		
CIP-002-5.1a	Attachment 1: 2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	This reference directly refers to the Planning Coordinator (PC), Transmission Planner (TP), and Reliability Coordinator (RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. After retirement of FAC-10-3, PCs and TPs will no longer be required to establish IROLs using FAC-010-3; however, IROLs will continue to be required to be established by the RC. Similar to Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a, FAC-014-3, Requirement R6, requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the Generator Owners (GO) and Transmission Owners (TOs). FAC-014-3 Requirement R6 specifically states, “Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a

		list of Facilities owned by that entity that are critical to the derivation of the IROL." While Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modify Requirement R2, Part 2.6 of Attachment 1 of CIP-002-5.1a to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise Requirement R2, Part 2.6 of Attachment 1 in response to the retirement of FAC-010-3 to eliminate PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's

		Planning Assessment for the Near-Term Transmission Planning Horizon.
CIP-014-2	Applicability 4.1.1.3 Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	This reference directly refers to the PC and TP (and RC) and certain facilities that have been identified by these entities as being critical to the derivation of an IROL. Similar to 4.1.1.3 of the Applicability section of CIP-014-2, FAC-014-3, Requirement R6 requires the Facilities (generation and/or transmission) identified by the RC as critical to the derivation of the IROL to be communicated to the GOs and TOs. FAC-014-3 Requirement R6 specifically states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." While 4.1.1.3 of the Applicability section of CIP-014-2 could benefit from a revision to eliminate the PC and TP in response to the retirement of FAC-010-3, no reliability gap is created if FAC-010-3 is retired prior to the revision of Requirement R2, Part 2.6 of Attachment 1 given the above requirements for the RC. Consideration should also be given to modifying 4.1.1.3 of the Applicability section of CIP-014-2 to focus on identification of Facilities – not the identification of IROLs as the limits themselves are immaterial to the goal. Accordingly, it may be appropriate for the Facilities identified as applicable to the CIP standard include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in

		the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. **Recommendations:** Revise 4.1.1.3 of the Applicability section of CIP-014-2 in response to the retirement of FAC-010-3 to eliminate the PC and TP responsibility for identification of Facilities critical to the derivation of IROLs. A future team should determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
COM standards		No Action Required
EOP standards		No Action Required
FAC standards		
FAC-003-4	**Introduction:** **4.2.2.** Each overhead transmission line operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator. **4.3.1.2.** Operated below 200kV identified as an element of an IROL under NERC Standard FAC-014 by the Planning Coordinator; or …	The Applicability section of the Introduction specifies "applicable lines" and includes overhead transmission lines (< 200 kV) identified as an element of an IROL by the PC. Requirements R1 and R2 reference "applicable lines" and IROLs as well. "Applicable lines" are specified for the identification of overhead transmission lines that require the levels of vegetation management required by the standard. All overhead transmission lines that operate at 200 kV and above are included as "applicable

	Requirements **R1.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the Minimum Vegetation Clearance Distance (MVCD) of its applicable line(s) which are either an element of an IROL, or an element of a Major WECC Transfer Path; operating within their Rating and all Rated Electrical Operating Conditions of the types shown below… **R2.** Each applicable Transmission Owner and applicable Generator Owner shall manage vegetation to prevent encroachments into the MVCD of its applicable line(s) which are not either an element of an IROL, or an element of a Major WECC Transfer Path.	lines" (4.2.1). Qualifications are then being made to include < 200 kV transmission lines (4.2.2 & 4.2.3) that have a high enough level of criticality to require the same vegetative management requirements as higher voltage transmission lines. The actual limit is not the focus, but rather, the identification of transmission lines that, when compromised, present the risk of potentially severe consequences and therefore should be subject to stricter vegetation management. The retirement of FAC-010 does not create a reliability gap here. The language in Parts 4.2.2 and 4.3.1.2 of FAC-003-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-014; however, IROLs are required to be established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." FAC-003-4 is applicable to GOs and TOs. Accordingly, these entities are made aware of IROLs and the facilities critical to the derivation of those IROLs from the RC as per FAC-014-3 Requirement R6 above. While Parts 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired

		prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 in response to the retirement of FAC-010-3 to eliminate references to the PC determining IROLs. A future team should determine the appropriateness for the elements identified as applicable to 4.2.2 and 4.3.1.2 of the Applicability section of FAC-003-4 include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
FAC-013-2	**Requirements** **R1.2.** A statement that the assessment shall respect known System Operating Limits (SOLs).	R 1.2 is not specific to Planning Horizon SOLs but the applicability of the overall standard is for PCs. The retirement of FAC-010-3 does not create a reliability gap here as SOLs will continue to be established by TOPs and communicated to PCs through FAC-014-3 Requirement R5. The PC can then use the SOL information to satisfy Requirement R1, R1.2. Requirement R1.2 does not specify whether the SOLs are sourced from the RC or by the PC. **Recommendations:** Consideration should also be given to clarify FAC-013-2 Requirement R1.2 to eliminate the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment.

		Possible solutions include changing the language of Requirement R1, R1.2 to reference the performance requirements per Table 1 of TPL-001-4, or revising the language to replace SOL with "Facility Ratings, System steady-state voltage limits, and the Transmission Planners' stability criteria." A future team should consider eliminating the use of the SOL term as applied to the Planning Coordinators Transfer Capability assessment as described above.
FAC-014-2	Requirements R3 – R5	Under Revision
INT standards		No Action Required
IRO standards		No Action Required
MOD standards		No Action Required
NUC standards		No Action Required
PER standards		No Action Required
PRC standards		
PRC-002-2	**Requirements:** **R5.** Each Responsible Entity shall: **5.1.** Identify BES Elements for which dynamic Disturbance recording (DDR) data is required, including the following: **5.1.2.** Any one BES Element that is part of a stability (angular or voltage) related System Operating Limit (SOL).	Direct language around SOL and IROL does not specify PC SOL methodology and therefore does not preclude the RC's methodology from determining the applicable limits. However, the time horizon for the requirement is "long-term planning." Additionally, the SOLs referred to are stability based only. The retirement of FAC-010-3 does not create a reliability gap here. IROLs and stability-related SOLs are communicated to the GOs

	5.1.4. One or more BES Elements that are part of an Interconnection Reliability Operating Limit (IROL).	and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." The Applicability section of PRC-002-2 describes the Responsibly Entities: 4.1.1 Eastern Interconnection – Planning Coordinator 4.1.2 ERCOT Interconnection – Planning Coordinator or Reliability Coordinator 4.1.3 Western Interconnection – Reliability Coordinator 4.1.4 Quebec Interconnection – Planning Coordinator or Reliability Coordinator Regardless of the designation of the Responsible Entity in a given Interconnection, either is able to provide the GOs and TOs the information in Requirement R5, Parts 5.1.2 and 5.1.4. The information is ultimately sourced from the RC, but FAC-014-3, Requirement R5, Parts 5.1, 5.2, and subparts requires the RC to communicate the relevant information to the PC, who, in turn, can communicate the information to the applicable GO and TO as required by PRC-002-2, Requirement R5, Parts 5.1.2 and 5.1.4. FAC-014-3 R5. Each Reliability Coordinator shall provide:

		5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL; 5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). While subparts 5.1.2 and 5.1.4 of PRC-002-2 would benefit from a revision in response to the retirement of FAC-010, the need for such a revision does not rise to the level of creating a reliability gap if FAC-010 is retired prior to the time these requirements can be changed. **Recommendations:** It is recommended that this standard be modified at some point in the future to update the designation of the Responsible Entities defined in the Standard. In the absence of this change, however, the currently defined Responsible Entities are capable of providing the necessary information through the mechanisms described above.
PRC-023-4	**Attachment B** - Criteria Section:	Direct reference to FAC-010 made in this attachment.

	If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit… B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.	Attachment B sets the applicability of facilities operated below 200 kV (similar to FAC-003). These items reference PRC-023-4, Requirement R6, to which Attachment B is applicable. The language in part B2 of Attachment B of PRC-023-4 specifically addresses IROLs determined in the planning horizon pursuant to FAC-010-3; however, IROLs are established by the RC, and the Facilities critical to the derivation of the IROL are communicated to the GOs and TOs through FAC-014-3, Requirement R6 which states, "Each Reliability Coordinator that is impacted by an IROL shall provide Transmission Owners and Generation Owners within its Reliability Coordinator Area a list of Facilities owned by that entity that are critical to the derivation of the IROL." Accordingly, the GO and the TO are able to use the IROL information provided by the Reliability Coordinator. While part B2 of Attachment B for PRC-023-4 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these subparts given the above requirements for the RC. **Recommendations:** Revise Attachment B of PRC-023-4 in response to the retirement of FAC-010-3 to eliminate the references to FAC-10, PC's determining IROLs and IROLs in the Planning Horizon for identification of circuits as a monitored Facility of an Interconnection Reliability Operating Limit (IROL).

		A future team should consider the appropriateness for the circuits identified as applicable to Attachment B of PRC-023-4 to include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
PRC-026-1	R1. Each Planning Coordinator shall, at least once each calendar year, provide notification of each generator, transformer, and transmission line BES Element in its area that meets one or more of the following criteria, if any, to the respective Generator Owner and Transmission Owner: Criteria: 1. Generator(s) where an angular stability constraint exists that is addressed by a System Operating Limit (SOL) or a Remedial Action Scheme (RAS) and those Elements terminating at the Transmission station associated with the generator(s). 2. An Element that is monitored as part of an SOL identified by the Planning Coordinator's methodology[1] based on an angular stability constraint. *{[1] NERC Reliability Standard FAC-014-2 – Establish and Communicate System Operating Limits, Requirement R3.}*	Direct reference is made to the PC's SOL Methodology. Footnote 1 on page 3 of 84 references FAC-014-2, R3. Similar to the reference identified in Requirement R5, Part 5.1.2 of PRC-002-2, Requirement R1 of PRC-026-1 references the identification of facilities that are sensitive to angular stability constraints. Stability-related SOLs are communicated to the Planning Coordinator through FAC-014-3, Requirement R5, Parts 5.1 and, 5.2: R5. Each Reliability Coordinator shall provide: 5.1. Each Planning Coordinator within its RC Area, SOLs for its RC Area (including the subset of SOLs that are IROLs) at least once every twelve calendar months. 5.2. Each impacted Planning Coordinator the following information for each established stability limit and each established IROL at least once every twelve calendar months: 5.2.1. The value of the stability limit or IROL; 5.2.2. Identification of the Facilities that are critical to the derivation of the stability limit or IROL; 5.2.3. The associated IROL Tv for any IROL;

		5.2.4. The associated Contingency(ies); and, 5.2.5. The type of limitation represented by the stability limit or IROL (e.g., voltage collapse, angular stability). With this information, the PC can communicate the necessary SOL information to the applicable GO and TO as required by PRC-026-1, Requirement R1. While Criteria 1 and 2 of PRC-026-1 would benefit from a revision in response to the retirement of FAC-010, no reliability gap is created if FAC-010-3 is retired prior to the revision of these criteria given the above requirement for the RC. **Recommendations:** Revise PRC-026-1, Requirement R1 in response to the retirement of FAC-010-3 to eliminate the term, "Planning Coordinator's Methodology" which references FAC-10 and remove the reference to SOLs identified by the PC. A future team should consider that the PRC-026 R1 criteria reference Elements associated with angular stability as identified in the PC or TP's Planning Assessment for the Near-Term Transmission Planning Horizon.
TOP standards		No Action Required
TPL standards		No Action Required
VAR standards		No Action Required

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Mapping Document for FAC-010-3

The Project 2015-09 standard drafting team (SDT) is proposing the retirement of the NERC FAC-010-3 Reliability Standard. The SDT further proposes a new paradigm regarding the coordination of the Planning Assessment (TPL-001-4) with the establishment of System Operating Limits (SOLs) used in operations. Along with the retirement of FAC-010-3, this new paradigm consists of a new FAC-015-1 Reliability Standard and revisions to the existing FAC-011-3 and FAC-014-2 Reliability Standards. The SDT proposal for a new FAC-015-1 Reliability Standard, along with the proposed revisions contained in FAC-011-4 and FAC-014-3, represent an improvement for planning and operations to better coordinate analysis input assumptions and System performance criteria to address the reliability issues that are ultimately faced in Real-time operations.

The proposed construct does not make use of an SOL Methodology applicable to the planning horizon as required by the currently-effective FAC-010-3 due to its overall redundancy with TPL-001-4. However, FAC-015-1, Requirements R1 – R3 ensure that Planning Assessments performed for the Near-Term Transmission Planning Horizon, are bounded by modeling data and performance criteria that are equally limiting or more limiting than those established in accordance with the Reliability Coordinator's (RC's) SOL Methodology. FAC-015-1, Requirements R1 – R3 respectively address Facility Ratings System steady state voltage limits, and stability performance criteria used in the development of Planning Assessments. These requirements focus on the three components of SOLs used in operations and facilitate continuity between operations and planning. Implementing the processes required in FAC-015-1 Requirements R1 – R3 provides the Planning Coordinator (PC) with Facility Ratings, System steady-state voltage limits, and stability performance criteria that are equally limiting or more limiting than the Facility Ratings, System Voltage Limits, and stability performance criteria established in accordance with the Reliability Coordinator's SOL Methodology.

FAC-015-1, Requirements R4 and R5 address the communication and use of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in Planning Assessments between PCs and Transmission Planners (TPs).

FAC-015-1, Requirement R6 requires the PC to communicate any instability, Cascading or uncontrolled separation, along with key supporting information, identified in the Planning Assessments to the RCs and to impacted Transmission Operators (TOPs). This information may be useful to RC and TOPs in the establishment of stability limits and IROLs that will ultimately be used in Real-time operations.

By implementing Requirements R1 – R6 of FAC-015, Facility Ratings, System steady-state voltage limits and stability criteria used in the development of the Planning Assessment are effectively bounded by the Facility Ratings, System Voltage Limits, and stability performance criteria define and established in accordance with the RC's SOL Methodology (FAC-011-4 & FAC-014-3). Furthermore, potentially critical stability information is communicated by planners to operators. The result is an improvement in reliability by ensuring continuity between planning and operations.

The remainder of this document provides a mapping of the existing requirements in FAC-010-3 to the proposed action by the SDT. For easier reference applicable information from Table 1 of TPL-001-4 is included below. References to notes a – j and Planning Events P0 – P7 will be included in the mapping table where appropriate.

TPL-001-4 Table 1 (steady state & stability performance criteria notes for planning events)

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.
d. Simulate Normal Clearing unless otherwise specified.
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.
h. Planning event P0 is applicable to steady state only.
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category P0 No Contingency
(Initial Condition - Normal System)

Category P1 Single Contingency
(Initial Condition - Normal System)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P2 Single Contingency
(Initial Condition - Normal System)

1. Opening of a line section w/o a fault
2. Bus Section Fault (SLG fault)
3. Internal Breaker Fault (non-Bus-tie Breaker) (SLG fault)
4. Internal Breaker Fault (Bus-tie Breaker) (SLG fault)

Category P3 Multiple Contingency
(Initial Condition - Loss of generator unit followed by System adjustments)
Loss of one of the following:

1. Generator (3 Ø fault)
2. Transmission Circuit (3 Ø fault)
3. Transformer (3 Ø fault)
4. Shunt Device (3 Ø fault)
5. Single Pole of DC line (SLG fault)

Category P4 Multiple Contingency
(Initial Condition - Normal System)

1. Generator (SLG fault)
2. Transmission Circuit (SLG fault)
3. Transformer (SLG fault)
4. Shunt Device (SLG fault)
5. Bus Section (SLG fault)
6. Loss of multiple elements caused by a stuck breaker (Bus-tie Breaker) attempting to clear a Fault on the associated bus

Category P5 Multiple Contingency
(Initial Condition - Normal System)
Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following:
Generator (SLG fault)

1. Transmission Circuit (SLG fault)
2. Transformer (SLG fault)
3. Shunt Device (SLG fault)
4. Bus Section (SLG fault)

Category P6 Multiple Contingency
(Initial Condition - Loss of one of the following followed by System adjustments.

1. Transmission Circuit
2. Transformer
3. Shunt Device
4. Single Pole of DC line)

Loss of one of the following:

1. Transmission Circuit (3 Ø fault)
2. Transformer (3 Ø fault)
3. Shunt Device (3 Ø fault)
4. Single Pole of DC line (SLG fault)

Category P7 Multiple Contingency
(Initial Condition - Normal System)
The loss of:

- Any two adjacent (vertically or horizontally) circuits on common structure (SLG fault)
- Loss of a bipolar DC line (SLG fault)

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R1.	The Planning Authority shall have a documented SOL Methodology for use in developing SOLs within its Planning Authority Area. This SOL Methodology shall:	**FAC-010-3, Requirement R1 is addressed by:** 1. TPL-001-4, Requirements R1, R5, and R6 2. MOD-032-1, Requirement R2 3. FAC-008-3 Requirements R2 and R3 **TPL-001-4, Requirement R1:** **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **R1.1** System models shall represent: **R1.1.1.** Existing Facilities **R1.1.2.** Known outage(s) of generation or Transmission	SOLs developed by the PC and TP for use in the planning horizon are addressed in other standards as described below. SOLs used in the Operations Planning, Same-day Operations, and Real-time Operations time horizons are developed in accordance with the RC's methodology as specified in FAC-011-4. The determination of Facility Ratings, System steady-state voltage limits, and stability performance criteria for use in the Long-term Planning time horizon are addressed as follows. It is important to note the new FAC-015-1 Reliability Standard bounds the following items as stated in the introduction of this document. **Facility Ratings** PCs and TPs are required, by TPL-001-4 Requirement R1, to maintain System models and to use data consistent with that which has been provided in accordance with MOD-032-1 (which supersedes the MOD-010 and MOD-012 standards). Facility Ratings are included in this data. These Facility Ratings: • Are determined in accordance with a Generator Owner's (GOs) or TO's Facility Ratings Methodology as required by FAC-008-3 R2 & R3 and

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	Facility(ies) with a duration of at least six months. **R1.1.3.** New planned Facilities and changes to existing Facilities **R1.1.4.** Real and reactive Load forecasts **R1.1.5.** Known commitments for Firm Transmission Service and Interchange **R1.1.6.** Resources (supply or demand side) required for Load **TPL-001-4, Requirement R5:** **R5.** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. **TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document,	• Are provided to the PC and TP by the Facility Owner as required by MOD-032-1 R2. **System Steady-State Voltage Limits** TPL-001-4 R5 requires the TP and PC to have criteria for acceptable System steady state voltage limits. These limits are used in the Planning Assessments. **Transient and Voltage Stability Performance Criteria** TPL-001-4 Requirement R6 requires the TP and PC to have documented criteria to identify system conditions such as Cascading, voltage instability, or uncontrolled islanding. This criteria is applied when performing Planning Assessments to identify instances of Cascading, voltage instability, or uncontrolled islanding.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. **MOD-032-1, Requirement R2:** **R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. **FAC-008-3, Requirement R2:** **R2.** Each Generator Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned equipment connected between the location specified in R1 and the point of	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		interconnection with the Transmission Owner that contains all of the following… **FAC-008-3, Requirement R3:** **R3.** Each Transmission Owner shall have a documented methodology for determining Facility Ratings (Facility Ratings methodology) of its solely and jointly owned Facilities (except for those generating unit Facilities addressed in R1 and R2) that contains all of the following…	
R1.1.	Be applicable for developing SOLs used in the planning horizon.		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. The requirements from TPL-001-4, MOD-032-1, and FAC-008-3 discussed above are applicable to the Long-term Planning time horizon and supersede the need for developing planning horizon SOLs.
R1.2.	State that SOLs shall not exceed associated Facility Ratings.	**TPL-001-4 Table1:** **Note: 'f'**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of SOLs in accordance with the PC's SOL Methodology. TPL-001-4 is constructed such that a Corrective Action Plan is developed to address those conditions where Facility Ratings are forecasted

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
			to be exceeded in response to a planning event. The implementation of the Corrective Action Plan ensures the System is planned so there are no exceedances of Facility Ratings.
R1.3.	Include a description of how to identify the subset of SOLs that qualify as IROLs.	**TPL-001-4, Requirement R6:** **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon or the development of IROLs in accordance with the PC's SOL Methodology. In the proposed construct, PC and TP identify instances of instability, Cascading, or uncontrolled separation per the criteria developed in TPL-001-4 and communicate those instances to the Reliability Coordinator via FAC-015-1, Requirement R6. IROLs are established by the RC as required by FAC-014-3. TPL-001-4, Requirement R6 requires PC and TPs to document criteria or a methodology for use in identifying Cascading, voltage instability, or uncontrolled islanding in the analysis conducted for the annual Planning Assessment. This criterion addresses the conditions described in the definition for Interconnection Reliability Operating Limit (IROL).
R2.	The Planning Authority's SOL Methodology shall include a requirement that SOLs provide BES	**TPL-001-4 Table 1**	The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	performance consistent with the following:		horizon. The SDT proposes retiring Requirement R2 and its subparts due to redundancy with TPL-001-4 performance requirements contained in Table 1 notes a – j. The TPL-001-4 criteria provide the performance criteria for studies within the planning horizon that serve as the basis of the annual Planning Assessment the standard requires the PC and TP produce.
R2.1.	In the pre-contingency state and with all Facilities in service, the BES shall demonstrate transient, dynamic and voltage stability; all Facilities shall be within their Facility Ratings and within their thermal, voltage and stability limits. In the determination of SOLs, the BES condition used shall reflect expected system conditions and shall reflect changes to system topology such as Facility outages.	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'** **TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Pre-contingency (Category P0) Bulk Electric System (BES) planned performance is addressed by TPL-001-4 Table 1 with notes a, f, and g specifying the applicable performance criteria. BES planned performance is based on expected system conditions and changes to system topology such as Facility outages as specified in TPL-001-4 Requirement R1.
R2.2.	Following the single Contingencies[1] identified in	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g'**	Single contingency (Categories P1 & P2) BES planned performance is addressed by TPL-001-4

[1] The Contingencies identified in R2.2.1 through R2.2.3 are the minimum contingencies that must be studied but are not necessarily the only Contingencies that should be studied.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	Requirement 2.2.1 through Requirement 2.2.3, the system shall demonstrate transient, dynamic and voltage stability; all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		Table 1 with notes a through j specifying the applicable performance criteria.
R2.2.1.	Single line to ground or three-phase Fault (whichever is more severe), with Normal Clearing, on any Faulted generator, line, transformer, or shunt device.	**TPL-001-4 Table1:** **Note: 'd'** **TPL-001-4 Table 1:** Categories P1 & P2 Single Contingency Events **TPL-001-4 Table 1:** **Footnote 2.** Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R2.2.2.	Loss of any generator, line, transformer, or shunt device without a Fault.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.2.3.	Single pole block, with Normal Clearing, in a monopolar or bipolar high voltage direct current system.	**TPL-001-4 Table1:** Categories P1 & P2 Single Contingency Events	
R2.3.	Starting with all Facilities in service, the system's response to a single Contingency, may include any of the following:	**TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to single contingencies are addressed in approved TPL-001-4 Table 1, including Consequential Load Loss and System Reconfiguration.
R2.3.1.	Planned or controlled interruption of electric supply to radial customers or some local network customers connected to or supplied by the Faulted Facility or by the affected area.	**TPL-001-4 Table1: Note: 'b'**	
R2.3.2.	System reconfiguration through manual or automatic control or protection actions.	**TPL-001-4 Table1: Note: 'e'**	
R2.4.	To prepare for the next Contingency, system adjustments may be made,	**TPL-001-4 Table1: Note: 'e'**	Allowable System adjustments for BES planned performance to prepare for the next

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	including changes to generation, uses of the transmission system, and the transmission system topology.	**TPL-001-4 Table 1:** Footnote 9**.** An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non- Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.	Contingency are addressed TPL-001-4 Table 1 note e and footnote 9.
R2.5.	Starting with all Facilities in service and following any of the multiple Contingencies identified in Reliability Standard TPL-003 the system shall demonstrate transient, dynamic and voltage stability;	**TPL-001-4 Table1:** **Notes: 'a', 'f', 'g' 'j'** **TPL-001-4 Table1:** Categories P3 – P7 Multiple Contingency Events	Multiple contingency BES planned performance is addressed as Category P3 - P7 in TPL-001-4 Table 1. These include the multiple contingency events that start with all Facilities in service (P4, P5 & P7). Notes a through j from Table 1 (above) specify the applicable performance criteria.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
	all Facilities shall be operating within their Facility Ratings and within their thermal, voltage and stability limits; and Cascading or uncontrolled separation shall not occur.		
R2.6.	In determining the system's response to any of the multiple Contingencies, identified in Reliability Standard TPL-003, in addition to the actions identified in R2.3.1 and R2.3.2, the following shall be acceptable:	**TPL-001-4, Requirement R2.7.3** **TPL-001-4 Table 1**	Allowable actions for BES planned performance in response to multiple contingencies are addressed in TPL-001-4 Requirement R2.7.3 and Table 1, including all actions that were acceptable in response to single Contingencies discussed above; and load shedding and curtailment of Firm Transmission Service.
R2.6.1.	Planned or controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers.	**TPL-001-4, Requirement R2, Part 2.7.3.** **2.7.3.** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking	Table 1 in TPL-001-4 specifies the conditions where service interruption is acceptable.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. **TPL-001-4 Table 1:** Footnote 9 (refer to R2.4 section) Footnote 12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.	
R3.	The Planning Authority's methodology for determining SOLs, shall include, as a minimum, a description of the following, along with any reliability margins applied for each:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (R5 had since been retired). Requirement R3 was identified as "More appropriate as a Guideline. This is a checklist."
R3.1.	Study model (must include at least the entire Planning Authority Area as well as the critical modeling details from other Planning Authority Areas that would impact the Facility or Facilities under study).	**TPL-001-4, Requirement R1:** **R1**. (refer to Requirement R2.1 section above)	Study model used for BES planned performance is specified in approved TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.2.	Selection of applicable Contingencies.	**TPL-001-4 Table1:** Categories P1 – P7 Planning Events	Applicable contingencies for BES planned performance are specified in approved TPL-001-4 Table 1.
R3.3.	Level of detail of system models used to determine SOLs.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Model details for BES planned performance are specified in approved TPL-001-4, Requirement R1.
R3.4.	Allowed uses of Remedial Action Schemes.	**TPL-001-4, Requirement R2, Part 2.7:** **2.7.** For planning events shown in TPL-001-4 Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with TPL-001-4, Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.1.** List System deficiencies and the associated actions needed to	TPL-001-4, Requirement R2.7 requires the development of a Corrective Action Plan to address system deficiencies. The Corrective Action Plan is required to include any automatic tripping or other automated protection that is required to meet the performance criteria in TPL-001-4 Table 1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		achieve required System performance. Examples of such actions include: • Installation, modification, or removal of Protection Systems or Special Protection Systems • Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. • Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.	
R3.5.	Anticipated transmission system configuration, generation dispatch and Load level.	**TPL-001-4, Requirement R1:** **R1.** (refer to Requirement R1 section above)	Anticipated transmission dispatch, generation, and load levels are incorporated into study models used for BES planned performance as specified in TPL-001-4, Requirement R1.

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
R3.6.	Criteria for determining when violating a SOL qualifies as an Interconnection Reliability Operating Limit (IROL) and criteria for developing any associated IROL T_V	See mapping for Requirement R1, Part 1.3	See mapping for Requirement R1.3
R4.	The Planning Authority shall issue its SOL Methodology, and any change to that methodology, to all of the following prior to the effectiveness of the change:		The proposed construct as described in the document introduction does not make use of an SOL Methodology applicable to the planning horizon. The modeling and performance requirements as well as the reliability objectives of FAC-010-3 are redundant with those in TPL-001-4. Furthermore, the Planning Assessment required by TPL-001-4 is distributed, in accordance with TPL-001-4 Requirement R8 and IRO-017 Requirement R3, to all applicable entities listed in FAC-010-3 Requirement R4. The SDT also acknowledges that the June 2013 report from the Independent Experts Review Project identified FAC-010-2.1, Requirements R3 and R4 as "Requirements Recommended for Retirement" in Appendix E of the report (Requirement R5 had since been retired). Requirement R4 was identified as "More appropriate as a Guideline. Description of
R4.1.	Each adjacent Planning Authority and each Planning Authority that indicated it has a reliability-related need for the methodology.	**TPL-001-4, Requirement R8:** **R8.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.	
R4.2.	Each Reliability Coordinator and Transmission Operator that operates any portion of the Planning Authority's Planning Authority Area.	**TPL-001-4, Requirement R8:** **R8.** (refer to Requirement R4, Part 4.1 section above) **IRO-017-1, Requirement R3:**	

Standard: FAC-010-3 — System Operating Limits Methodology for the Planning Horizon			
Requirement in Approved Standard		**Translation to New Standard or Other Action**	**Description and Change Justification**
		R3. Each Planning Coordinator and Transmission Planner shall provide its Planning Assessment to impacted Reliability Coordinators**.**	appropriate coordination does not rise to a Standard.”
R4.3.	Each Transmission Planner that works in the Planning Authority’s Planning Authority Area.	See mapping for Requirement R4, Part 4.1	

Proposed Definition of "System Voltage Limit"

Term: "System Voltage Limit"

Definition:

The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.

Rationale

As noted above, the Project 2015-09 standard drafting team (SDT) also proposes to add the term System Voltage Limit to the NERC Glossary with the following definition:

> *The maximum and minimum steady-state voltage limits (both normal and emergency) that provide for acceptable System performance.*

The SDT identified a need to develop a NERC Glossary definition for the term System Voltage Limit to address confusion within industry as to what constitutes a system voltage limit. As part of its informal comment period on initial drafts of FAC-011-4 and FAC-014-3 (July 14- August 12, 2016), the SDT requested industry comment on whether there is a need to clarify what constitutes system voltage limits through a defined term in the NERC Glossary. The SDT proposed the following definition: "The maximum and minimum steady-state voltages (both Normal and Emergency) that provide for reliable system operations."

The vast majority of commenters indicated support for developing a definition for System Voltage Limits but noted a few concerns with the proposed definition. In response to those comments, the SDT made the following revisions:

- The word "limits" was added to clarify that it is a numeric value.
- The terms "Normal" and "Emergency" were changed to lower case as "Normal" is not defined in the NERC Glossary, and the SDT concluded that the NERC defined term "Emergency" was not appropriate.
- The phrase "reliable system operations" was replaced with "acceptable System performance" because the SDT determined that this language was more reflective of the desired intent behind the definition.
- The SDT used the NERC Glossary term "System" as the definition implies that System Voltage Limits should result in acceptable performance (from a voltage perspective) of the overall System.

The proposed System Voltage Limit definition does not specify whether the Transmission Operator would be required to provide a "System Voltage Limit" for each bus on its system, or if the Transmission Operator would need to provide a single high and low limit that is applicable to its entire system. The SDT intends for the Reliability Coordinator's System Operating Limits (SOL) Methodology to dictate the manner in which

System Voltage Limits should be established. The proposed definition allows Reliability Coordinators to have such flexibility, provided the requirements in proposed FAC-011-4 are met.

Additionally, the System Voltage Limit definition allows for differing time components that may be associated with short term or dynamic ratings. The SDT's intent is to allow the flexibility to establish System Voltage Limits consistent with the Reliability Coordinator's SOL Methodology, provided the requirements in proposed FAC-011-4 are met. The proposed definition specifies that System Voltage Limits must include normal and emergency maximum and minimum limits, and that these limits provide for acceptable System performance (in the context of voltage performance). According to the definition, it is acceptable for a Reliability Coordinator's SOL Methodology to allow for System Voltage Limits to include a normal limit and multiple emergency limits, which may have associated time values similar to the way emergency Facility Ratings are associated with time values. As discussed below, this concept is supported by the proposed definition of SOL Exceedance which states, in relevant par: "Bus voltage is outside the highest or lowest emergency System Voltage Limit, or outside a System Voltage Limit for which there is not sufficient time to bring the bus voltage to defined levels should the Contingency occur

Lastly, the proposed definition of System Voltage Limit does not explicitly distinguish between a voltage limit and a voltage rating. That is because proposed FAC-011-4 requires that System Voltage Limits respect equipment voltage ratings.

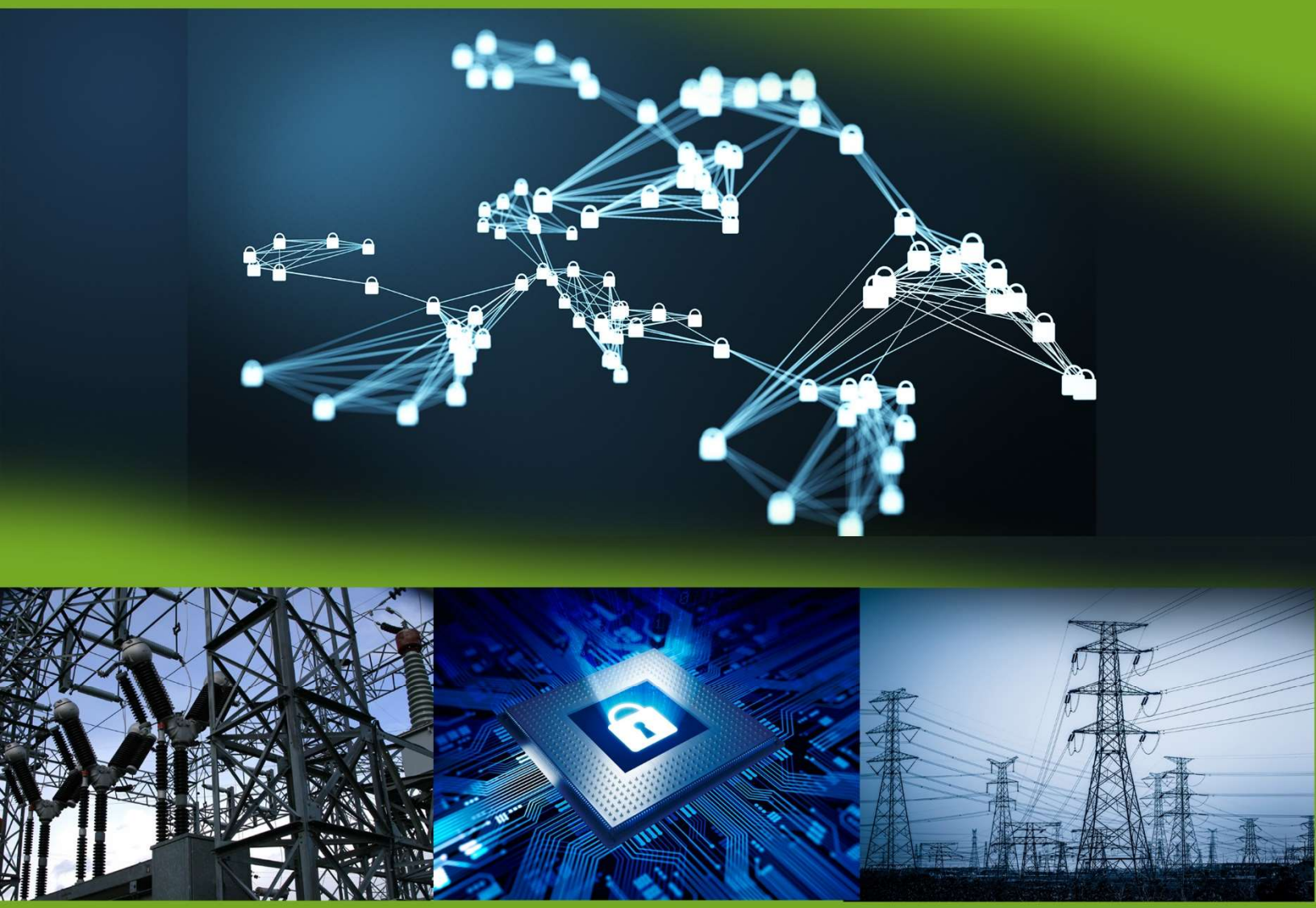
Potential Standards for Use of New Term: "System Voltage Limit"

These standard(s) were identified as potential areas that may benefit from the use of the new term. The SDT is in the process of evaluating these standards with respect to incorporating the definition.

- FAC-003-4 Transmission Vegetation Management
- MOD-001-2 Available Transmission System Capability
- PRC-012-2 Remedial Action Schemes
- TPL-001-4 Transmission System Planning Performance Requirements
- TPL-007-1 Transmission System Planned Performance for Geomagnetic Disturbance Events
- VAR-001-4.1 Voltage and Reactive Control

2017 Staff Report

Lessons Learned from Commission-Led CIP Version 5 Reliability Audits



Federal Energy Regulatory Commission October 2017

FEDERAL ENERGY REGULATORY COMMISSION

2017 Staff Report
Lessons Learned from Commission-Led CIP Version 5 Reliability Audits

Prepared by Staff of the

Office of Electric Reliability

Federal Energy Regulatory Commission

Washington, D.C.

October 6, 2017

The matters presented in this staff report do not necessarily represent the views of the Federal Energy Regulatory Commission, its Chairman, or individual Commissioners, and are not binding on the Commission.

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Introduction

The staff of the Division of Reliability Standards and Security in the Office of Electric Reliability, with assistance of staff from the Division of Audits and Accounting in the Office of Enforcement, of the Federal Energy Regulatory Commission (Commission) has completed non-public audits of several registered entities of the Bulk Electric System (BES).[1] The audits evaluated the registered entities' compliance with the applicable mandatory Reliability Standards for the Bulk-Power System Critical Infrastructure Protection (CIP) Reliability Standards (CIP Reliability Standards).[2] Staff from Regional Entities and the North American Electric Reliability Corporation (NERC) participated on the audits, including the on-site portion. The audits were completed during Fiscal Years 2016 and 2017 (FY2016 and FY2017, respectively).

The audits provided audited entities an assessment of their compliance status in the audited areas. Staff found that, for the first series of completed non-public audits, most of the cyber security protection processes and procedures adopted by the audited entities met the mandatory requirements of the CIP Reliability Standards. Staff also found instances of potential compliance infractions. Additionally, staff identified possible areas of improvement in the security posture of audited entities that are not specifically addressed by the CIP Reliability Standards. The audits afforded audited entities opportunities to learn of areas for improvement in their security posture and staff recommended proposals to addresses the matters.

This anonymized summary report informs the regulated community and the public of lessons learned from the audits, including insights into the cyber security and CIP compliance issues encountered by registered entities. This report provides information and recommendations to NERC, Regional Entities, and registered entities that staff believes is useful in their assessments of risk, compliance, and overall cyber security. Moreover, this information may be generally beneficial to the utility-based cyber security community to improve the security of the BES.

[1] BES is defined in the "Glossary of Terms Used in NERC Reliability Standards" (NERC Glossary), http://www.nerc.com/files/glossary_of_terms.pdf.

[2] 18 C.F.R. Part 40 (2017).

CIP Reliability Standards

Section 215 of the Federal Power Act (FPA) requires a Commission-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[3] Reliability Standards may be enforced by the ERO, subject to Commission oversight, or by the Commission independently. The Commission established a process to select and certify an ERO,[4] and subsequently certified NERC.[5]

Pursuant to section 215 of the FPA, on January 28, 2008, the Commission approved an initial set of eight mandatory CIP Reliability Standards pertaining to cybersecurity.[6] In addition, the Commission directed NERC to develop certain modifications to the CIP Reliability Standards. Since 2008, the CIP Reliability Standards have undergone multiple revisions to address Commission directives and respond to emerging cybersecurity issues. The CIP Reliability Standards are designed to mitigate the cybersecurity risks to BES facilities, systems, and equipment, which, if destroyed, degraded, or otherwise rendered unavailable as a result of a cybersecurity incident, would affect the reliable operation of the Bulk-Power System.

[3] 16 U.S.C. 824o (2012).

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

[5] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,190, *order on reh'g*, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa, Inc. v. FERC,* 564 F.3d 1342 (D.C. Cir. 2009).

[6] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, *denying reh'g and granting clarification*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229, *order denying clarification*, Order No. 706-C, 127 FERC ¶ 61,273 (2009).

Audit Scope and Methodology

The Commission initiated its CIP Reliability Standards audits of registered entities of the BES in FY2016. The audits focused on evaluating compliance with CIP Reliability Standards version 5 (CIP v5) for the period after July 1, 2016.[7] The Commission also evaluated compliance with CIP Reliability Standards version 3 (CIP v3), for the period of each audited entity's last CIP compliance audit through June 30, 2016 (the effective end date of CIP v3).[8]

Audit fieldwork primarily consisted of data requests and reviews, teleconferences, and a site visit to each entity's facilities. Prior to a site visit, staff issued data requests to gather information pertaining to an entity's CIP activities and operations, and conducted teleconferences to discuss the audit scope and objectives, data requests and responses, technical and administrative matters, and compliance concerns. During a site visit, staff interviewed an entity's subject matter experts (SMEs); observed operating practices, processes, and procedures used by its staff in real-time; and examined its functions, operations, practices, and regulatory and corporate compliance culture. Additionally, staff interviewed employees and managers responsible for performing tasks within the audit scope and analyzed documentation to verify compliance with requirements; conducted several field inspections and observed the functioning of certain assets identified by an entity as High, Medium, or Low Impact; and interviewed compliance program managers, staff, and employees responsible for day-to-day compliance and regulatory oversight activities.

The data, information, and evidence provided by an entity were evaluated for sufficiency, appropriateness, and validity. Documentation submitted in the form of policies, procedures, e-mails, logs, studies, data sheets, etc., were validated, substantiated, and crosschecked for accuracy as appropriate. For certain CIP Reliability Standard Requirements, sampling was performed to test compliance.

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[7] *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037 (2016), *reh'g denied*, 156 FERC ¶ 61,052; Reliability Standards: CIP-003-6, CIP-004-6, CIP-006-6, CIP-007-6, CIP-009-6, CIP-010-2, and CIP-011-2; *Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 145 FERC ¶ 61,160 (2013), *order on clarification and reh'g*, 146 FERC ¶ 61,188 (2014); Reliability Standards: CIP-002-5.1a, CIP-005-5, and CIP-008-5.

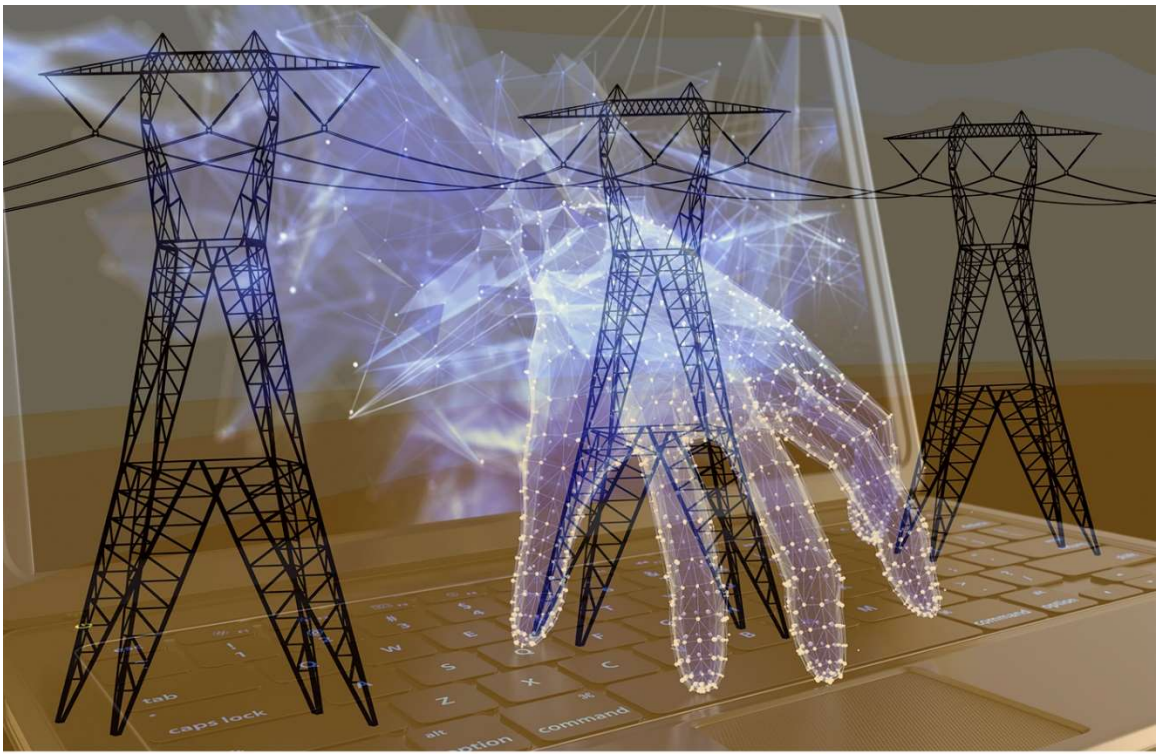
[8] *Revised Reliability Standards for Critical Infrastructure Protection*, 128 FERC ¶ 61,291, *order denying reh'g and granting clarification*, 129 FERC ¶ 61,236 (2009), *order on compliance*, 130 FERC ¶ 61,271 (2010); Reliability Standards: CIP-002-3, CIP-003-3, CIP-004-3, CIP-005-3, CIP-006-3, CIP-007-3, CIP-008-3, and CIP-009-3.

Overview of Lessons Learned

Staff derived the following lessons learned from the audits it conducted. These lessons are directed toward responsible entities to improve their compliance with the CIP Reliability Standards and their overall cyber security posture.

1. Conduct a thorough review of CIP Reliability Standards compliance documentation; identify areas of improvement to include but not be limited to instances where the documented instructional processes are inconsistent with actual processes employed or where inconsistencies exist between documents; and modify documentation accordingly.
2. Review communication protocols between business units related to CIP operations and compliance, and enhance these protocols where appropriate to ensure complete and consistent communication of information.
3. Consider all owned generation assets, regardless of BES-classification, when evaluating impact ratings to ensure proper classification of BES Cyber Systems.
4. Identify and categorize cyber systems used for supporting generation, in addition to the cyber systems used to directly control generation.
5. Ensure that all shared facility categorizations are coordinated between the owners of the shared facility through clearly defined and documented responsibilities for CIP Reliability Standards compliance.
6. Conduct a detailed review of contractor personnel risk assessment processes to ensure sufficiency and to address any gaps.
7. Conduct a detailed review of physical key management to ensure the same rigor in policies and testing procedures used for electronic access is applied to physical keys used to access the Physical Security Perimeter (PSP).
8. Enhance procedures, testing, and controls around manual transfer of access rights between personnel accessing tracking systems, Physical Access Control Systems (PACS), and Electronic Access Control Monitoring Systems (EACMS) or, alternatively, consider the use of automated access rights provisioning.
9. Ensure that access permissions within personnel access tracking systems are clearly mapped to the associated access rights within PACS and EACMS.
10. Ensure that policies and testing procedures for all electronic communications protocols are afforded the same rigor.
11. Perform regular physical inspections of BES Cyber Systems to ensure no unidentified Electronic Access Points (EAPs) exist.
12. Review all firewall rules and ensure access control lists follow the principle of "least privilege."
13. For each remote cyber asset conducting Interactive Remote Access (IRA), disable all other network access outside of the connection to the BES Cyber System that is being remotely accessed, unless there is a documented business or operational need.

14. Enhance processes and controls around the use of manual logs, such as using highly visible instructions outlining all of the parts of the requirement with each manual log, to consistently capture all required information.
15. Enhance processes and procedures for documenting the determination for each cyber asset that has no provision for disabling or restricting ports, to ensure consistency and detail in the documentation.
16. Consider employing host-based malicious code prevention for all cyber assets within a BES Cyber System, in addition to network level prevention, for non-Windows based cyber assets as well as Windows-based cyber assets.
17. Implement procedures and controls to monitor or limit the number of simultaneously successful logins to multiple different systems.
18. Implement procedures to detect and investigate unauthorized changes to baseline configurations.
19. Ensure that all commercially available enterprise software tools are included in BES Cyber System Information (BSCI) storage evaluation procedures.
20. Enhance documented processes and procedures for identifying BCSI to consider the NERC Critical Infrastructure Protection Committee (CIPC) guidance document, "Security Guideline for the Electricity Sector: Protecting Sensitive Information."
21. Document all procedures for the proper handling of BCSI.



Lessons Learned Discussion

General Practices

1. Conduct a thorough review of CIP Reliability Standards compliance documentation; identify areas of improvement to include but not be limited to instances where the documented instructional processes are inconsistent with actual processes employed or where inconsistencies exist between documents; and modify documentation accordingly.

Relates To

All CIP Reliability Standards

Entities generally had sufficient security practices that satisfied the CIP Reliability Standards, however documentation on such practices into formal procedures could be improved. Actual practices sometimes included additional steps not included in the formal documented procedures, or differed slightly from the written record on the procedures. Such inconsistencies can have significant impacts on an entity's cyber security program because a lack of complete and accurate documentation of cyber security practices heightens the risk of improper implementation by employees.

2. Review communication protocols between business units related to CIP operations and compliance, and enhance these protocols where appropriate to ensure complete and consistent communication of information.

Relates To

All CIP Reliability Standards

Audited entities generally performed adequately with regard to having sufficient security controls that satisfied the CIP Reliability Standards, but entities' communications between their various business units could be improved as to these controls. Clear and consistent communication between operational departments and an entity's human resource and information technology departments is imperative to CIP Reliability Standards compliance and the entity's cyber security posture as a whole. For example, poor communication could result in inappropriate delays in revocation of access rights for former employees or transferred employees.

Identifying BES Cyber Systems

3. Consider all owned generation assets, regardless of BES-classification, when evaluating impact ratings to ensure proper classification of BES Cyber Systems.

Relates To
CIP-002-5.1a Requirement R1 Identify BES Cyber Systems

While identification of BES Cyber Systems was generally performed adequately by the audited entities, there was some confusion regarding the generation assets that should be considered when evaluating the rating impact classification of BES Cyber Systems. Reliability Standard CIP-002-5.1a Attachment 1 identifies aggregated thresholds to determine the categorization of a BES Cyber System. For example, Criteria 2.11 requires categorization as Medium Impact of all Control Centers or backup Control Centers, not already categorized as High Impact, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. To determine whether a generation Control Center or back-up Control Center meets the 1500 MW threshold, the MW capacity of both BES generation and non-BES generation are considered. During audit fieldwork, staff found that some entities were only considering BES generation in applying Criteria 2.11, and therefore excluding all "non-BES generation" in their calculations.[9]

For example, a single generator operating with an individual nameplate of 10 MVA would not be included in the BES, and thus not have to categorize its cyber systems. However, a Control Center that controls 150 10-MVA generating resources would have to categorize its cyber systems, some possibly at a Medium Impact rating.[10] Ensuring that all owned generation assets, regardless of BES-classification, are considered in addressing Attachment 1 reduces the risk of improper identification and classification, and insufficient protection, of BES Cyber Systems.

[9] Per the BES Definition, generation resources are included if connected to an Interconnection at a voltage of 100 kV or above and either (a) a gross individual nameplate rating greater than 20 MVA; or, (b) a gross plant/facility aggregate nameplate rating greater than 75 MVA. The BES definition is not used to determine the impact rating of BES Cyber Systems. CIP-002-5.1a Attachment 1 does not define, or differentiate between, the terms "BES Generation," and "Non-BES Generation."

[10] CIP-002-5.1a (Cyber Security - BES Cyber System Categorization), Attachment 1 (Impact Rating Criteria), Criteria 2.11.

4. Identify and categorize cyber systems used for supporting generation, in addition to the cyber systems used to directly control generation.

Relates To
CIP-002-5.1a Requirement R1 Identify BES Cyber Systems

While identification of BES Cyber Systems that were used to directly control generation units was generally performed adequately by the entities, the identification of BES Cyber Systems that are used to control generation "support systems" could be improved.[11] In many cases inadequate documentation of "supporting systems" for BES Cyber Systems may have increased the entity's compliance risk of not correctly identifying all BES Cyber Systems.

5. Ensure that all shared facility categorizations are coordinated between the owners of the shared facility through clearly defined and documented responsibilities for CIP Reliability Standards compliance.

Relates To
CIP-002-5.1a Requirement R1 Identify BES Cyber Systems

The coordination between two or more owners of a shared BES facility for compliance with the CIP Reliability Standards could be improved. The identification and categorization of the assets at such shared facilities were not consistently coordinated between the owners. The underlying operating agreements did not clearly delineate the compliance responsibilities of each entity, which heightens the risk of devices being overlooked for required protections.

[11] Generator support systems may include fuel handling, water handling, air handling, exhaust handling, and other systems that are used to support the operations of the unit.

Personnel & Training

6. Conduct a detailed review of the contractor personnel risk assessment processes to ensure sufficiency and to address any gaps.

Relates To
CIP-004-6 Requirement R3 Personnel Risk Assessment Program

Personnel risk assessments (PRA) were generally performed and documented adequately for employees of an entity, but the PRAs for contractors were not consistently performed and documented. These deficiencies largely resulted from entities not evaluating contractors' processes or authorizing different PRA processes for contractors than those the entities used for their own employees. This led to inconsistencies in performance and documentation that heighten the risk of improper management of personnel with access to BES Cyber Systems.

7. Conduct a detailed review of physical key management to ensure the same rigor in policies and testing procedures used for electronic access is applied to physical keys used to access the Physical Security Perimeter (PSP).

Relates To
CIP-004-6 Requirement R4 Access Management Program

While audited entities generally had sufficient controls to limit electronic access to their PSP (i.e., keypads or badge readers for doors), the controls surrounding the use of physical keys to access PSPs could be improved. Physical keys were used less frequently than electronic access, generally provided access to lower impact facilities, and/or were only used as a secondary means to electronic access. However, the physical keys still provide access to PSPs and should be afforded the same level of control as afforded for electronic access.

8. Enhance procedures, testing, and controls around manual transfer of access rights between personnel accessing tracking systems, Physical Access Control Systems (PACS), and Electronic Access Control Monitoring Systems (EACMS) or, alternatively, consider the use of automated access rights provisioning.

Relates To

CIP-004-6 Requirement R4 Access Management Program

Most entities used either proprietary or customized Enterprise Resource Management systems (e.g., SAP, PeopleSoft, etc.), collectively referred to as Personnel Access Tracking Systems (PATS), to manage the authorization of physical access to their PSPs and electronic access to their BES Cyber Systems. The authorizations would then be promulgated, usually manually, to the corresponding PACS[12] and EACMS,[13] respectively. Staff found that while updates from the PATS to the PACS and EACMS were generally performed adequately, the manual promulgation led to instances of orphan records in the PATS and untimely updates to the PACS and EACMS, heightening the risk of improper access to the entity's PSPs and BES Cyber Systems. The higher risks for access control deficiencies may be due to the manual promulgation of the access rights. Entities should consider a detailed review of their policies and testing procedures for manual promulgation between PATS, PACS, and EACMS, or alternatively consider implementing automated access rights provisioning from the PATS to the PACS and EACMS.

[12] The NERC Glossary defines PACS as Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.

[13] The NERC Glossary defines EACMS as Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This definition includes Intermediate Systems. Examples of EACMS are Active Directory and other types of directory-services servers.

9. Ensure that access permissions within personnel access tracking systems are clearly mapped to the associated access rights within PACS and EACMS.

Relates To

CIP-004-6 Requirement R4 Access Management Program

Access permissions granted by entities within their PATS for employees or contractors may grant multiple types of access (i.e., physical, electronic, or informational). In some cases, these multi-faceted permissions were not clearly mapped to the type of access being granted. Lack of clarity between these permissions and the associated access rights heightens the risk of incorrect access permissions for certain employees or contractors. These risks may be lowered by reviewing the mappings, and clarifying, as appropriate, the PATS permissions within the PACS and EACMS.

Electronic Security Perimeters

10. Ensure that policies and testing procedures for all electronic communications protocols are afforded the same rigor.

Relates To

CIP-005-5 Requirement R1 Electronic Security Perimeter

Most entities use the Internet protocol suite for routable communication. The Internet protocol suite is composed of various protocols encapsulated within Internet Protocol (IP), such as the Transmission Control Protocol (TCP), the Internet Control Message Protocol (ICMP), and the User Datagram Protocol (UDP). While entities generally applied sufficient controls regarding access permissions for most Internet protocol suite communication, controls for all of the Internet protocol suite communication could be improved.

11. Perform regular physical inspections of BES Cyber Systems to ensure no unidentified Electronic Access Points (EAPs) exist.

Relates To

CIP-005-5 Requirement R1 Electronic Security Perimeter

While entities generally used an identified EAP[14] for all External Routable Connectivity (ERC),[15] there were some instances where an identified EAP was not used. These deficiencies usually occurred when a cyber asset within a BES Cyber System was directly connected to an outside network without going through an identified EAP, usually for troubleshooting or maintenance purposes, but the connection was left in place after the troubleshooting or maintenance was complete. Such connections pose a high risk to the security posture of the BES Cyber System.

12. Review all firewall rules and ensure access control lists follow the principle of "least privilege."

Relates To

CIP-005-5 Requirement R1 Electronic Security Perimeter

While entities generally implemented and maintained their firewall rules appropriately, there were some instances where firewall rules will allow traffic from any source or to any destination. This is generally considered to be an insecure access control rule because it employs no aspects of the principle of least privilege. Cybersecurity best practices include minimizing the use of any source or to any destination, as the vulnerability could be used for data exfiltration.

[14] The NERC Glossary defines EAP as a Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter. In most cases, this can be generally or simply considered a "firewall."

[15] The NERC Glossary defines ERC as the ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection. Often the bi-directional routable protocol connection is a protocol from the Internet protocol suite, such as TCP/IP, UDP/IP, or ICMP/IP.

13. For each remote cyber asset conducting Interactive Remote Access (IRA), disable all other network access outside of the connection to the BES Cyber System that is being remotely accessed, unless there is a documented business or operational need.

Relates To

CIP-005-5 Requirement R2 Interactive Remote Access Management

Most entities' practices for conducting IRA[16] allow for other network communications to be made by the remote cyber asset conducting the IRA session. Although no current CIP Reliability Standard requirement directly limits other network communications on a remote cyber asset conducting an IRA, limiting all other connections minimizes the overall attack surface of the entity while conducting an IRA and enhances its cyber security posture. Disabling other network access would include: disabling split tunneling if the IRA cyber asset is using a Virtual Private Network to connect to an Intermediate System; disabling dual-homing if the IRA cyber asset has more than one network connection; or disallowing general Internet access.

[16] The NERC Glossary defines IRA as User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate System and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.

Physical Security of BES Cyber Systems

14. Enhance processes and controls around the use of manual logs, such as highly visible instructions outlining all of the parts of the requirement with each manual log, to consistently capture all required information.

Relates To

CIP-006-6 Requirement R2 Visitor Control Program

Entities generally maintained complete visitor access control logs of physical access to the PSPs, however certain manual processes could be improved. The use of manual logs in certain instances led to failures to record pieces of information required to be recorded for each visitor (e.g., visitor's name, time of entry, time of exit, etc.). Such deficiencies were sometimes caused by inadequate controls for the use of manual logs. This risk could be lowered if highly visible instructions outlining all of the parts of the requirement were located in or near each manual log.

Systems Security Management

15. Enhance processes and procedures for documenting the determination for each cyber asset that has no provision for disabling or restricting ports, to ensure consistency and detail in the documentation.

Relates To
CIP-007-6 Requirement R1 Ports and Services

While entities generally implemented strong processes for ensuring that only logical network accessible ports that had been determined to be needed were enabled, the documentation of such determinations could be improved. CIP v5 provides a previously unavailable exemption for devices that have no provision for disabling or restricting logical ports. While entities would often document their determination for logical network accessible ports on devices that can disable or restrict logical ports, the entities would often overlook the documentation regarding devices that cannot disable or restrict logical ports. CIP v5 requires entities to document the details of such determination for each cyber asset, even for cyber assets that have no provision for disabling or restricting ports.

16. Consider employing host-based malicious code prevention for all cyber assets within a BES Cyber System, in addition to network level prevention, for non-Windows based cyber assets as well as Windows-based cyber assets.

Relates To
CIP-007-6 Requirement R3 Malicious Code Prevention

While entities generally had strong processes and procedures to deter, detect, and prevent malicious code at the host level (i.e., within the cyber assets themselves) for all of the Windows-based cyber assets within a BES Cyber System, the processes and procedures around non-Windows based cyber assets could be improved.[17] Historically, non-Windows based cyber assets have had minimal, if any, malicious code designed to disrupt them. The lack of malicious code targeting non-Windows cyber assets combined with lack of options for reliability host based malicious code prevention methods has led entities to rely on network based malicious code prevention. However, malicious code targeting non-Windows cyber assets is on the rise, and there are now reasonable host-based malicious code prevention options available. Entities relying solely on network based malicious code prevention for cyber assets operate at a heightened cyber security risk.

[17] Non-Windows based cyber assets within a BES Cyber System normally are cyber assets running Unix-like operating systems (e.g., Linux, HP-UX, AIX, Solaris).

17. Implement procedures and controls to monitor or limit the number of simultaneously successful logins from different locations.

Relates To

CIP-007-6 Requirement R5 System Access Control

Entities generally had strong procedures and controls for limiting the number of unsuccessful authentication attempts to critical systems and monitoring for unsuccessful authentication attempts through the use of alerts. However, most entities did not have procedures and controls in place to monitor for multiple successful logins to critical systems simultaneously from different locations. Although the CIP Reliability Standards do not specify a limit on the number of simultaneous successful logins a single user can have, and there are legitimate needs for some users to be logged into critical systems simultaneously, it is important to monitor such instances if occurring from different locations to ensure they are authentic.

Configuration Management

18. Implement procedures to detect and investigate unauthorized changes to baseline configurations.

Relates To

CIP-010-2 Requirement R2 Configuration Monitoring

Entities generally had implemented appropriate procedures to monitor for changes to the baseline configurations of their cyber assets, but the procedures for investigating detected unauthorized changes to baseline configurations could be improved. Documented processes for investigating detected unauthorized changes limit the risk that entities will not consistently prevent such unauthorized changes from reoccurring.

Information Protection

19. Ensure that all commercially available enterprise software tools are included in BES Cyber System Information (BSCI) storage evaluation procedures.

Relates To CIP-011-2 Requirement R1 Information Protection

Entities generally had strong procedures in place to identify and protect BCSI stored on most storage platforms (e.g., locked room with drawings containing BCSI information, cyber assets acting as file servers); however, the procedures around BCSI stored in enterprise software tools could be improved. These tools, usually performing functions like logging analysis or configuration management, are commercially available client-server software applications that may be located on an entity's corporate network. Such tools should be afforded the same protection as any other storage platform that contains BCSI.

20. Enhance documented processes and procedures for identifying BCSI to consider the NERC Critical Infrastructure Protection Committee (CIPC) guidance document, "Security Guideline for the Electricity Sector: Protecting Sensitive Information."

Relates To CIP-011-2 Requirement R1 Information Protection

While entities generally had sufficient security controls to identify and protect BCSI, most entities' BCSI programs still fell short of the guidance listed in the NERC CIPC[18] document, "Security Guideline for the Electricity Sector: Protecting Sensitive Information."[19] Entities could enhance their documented processes and procedures for identifying BCSI by taking into consideration this NERC CIPC document.

[18] NERC's CIPC coordinates NERC's security initiatives and serves as an expert advisory panel to NERC in the areas of physical security and cybersecurity.

[19] http://www.nerc.com/comm/CIPC/Protecting%20Sensitive%20Information%20Guideline%20Task1/Protecting%20Sensitive%20Information%20Guideline%20(PSIGTF).pdf.

21. Document all procedures for the proper handling of BCSI.

Relates To

CIP-011-2 Requirement R1 Information Protection

While entities generally had sufficient security controls to identify and protect BCSI, procedures for labeling, printing, and using external storage to transfer BCSI could be improved. Staff training was often the primary tool for communicating such procedures around BCSI rather than documented formal procedures. This method heightens the risk of improper management of BCSI.

Northeast Power Coordinating Council, Inc. 2017 General Meeting

Resilience

Guy V. Zito

NPCC AVP - Standards

Merriam Webster Definition of Resilience-

1 : the capability of a strained body to recover its size and shape after deformation caused especially by compressive stress

2 : an ability to recover from or adjust easily to misfortune or change

The National Infrastructure Advisory Council-Critical Infrastructure Resilience

"…the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event"

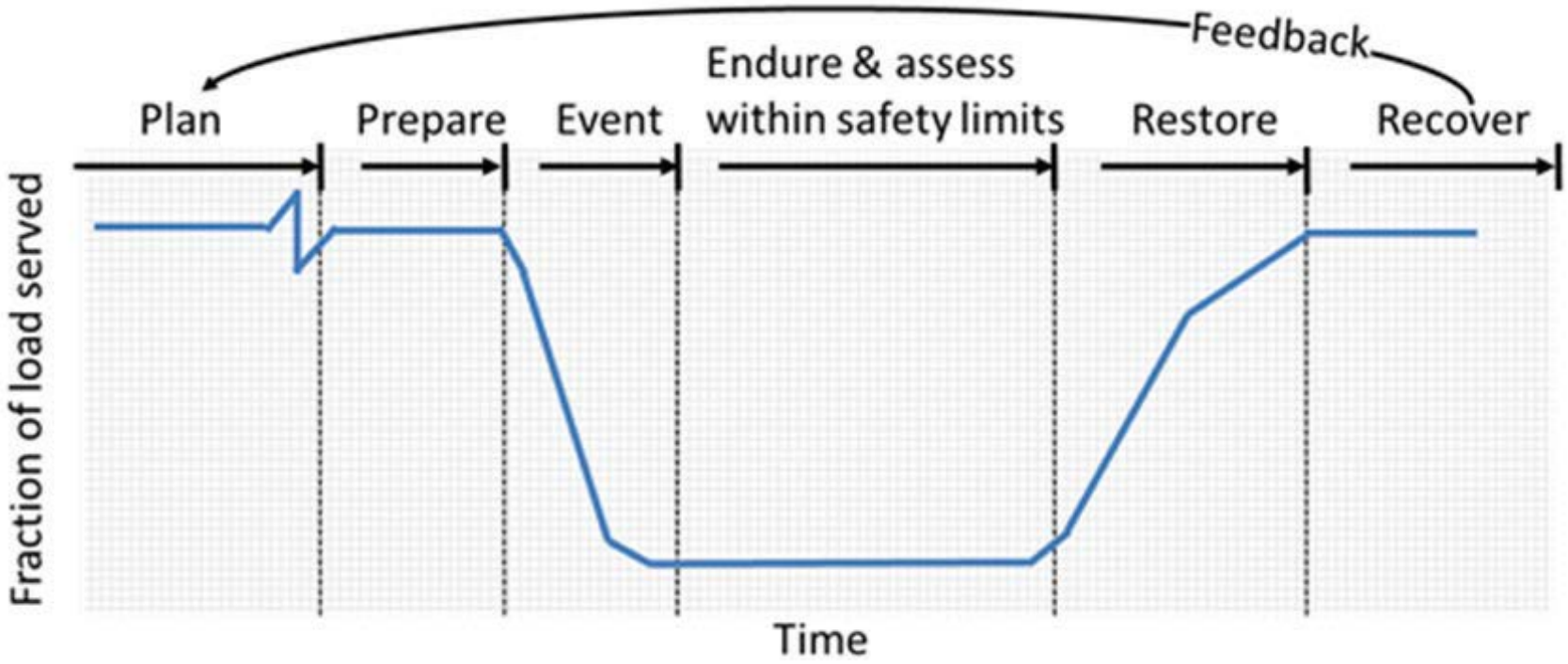
Resilience is not-

Reliability vs. Resiliency

Dependable Power System

- Reliability
- Resilience
- Maintainability
- Availability

Time Series of a Major Outage



[- **Reliability** -][- **Resilience** -]
[**Maintainability – Availability**]

Setting Expectations for the Industry

- "National Electric Grid Security and Resilience Action Plan"
- "Enhancing the Resilience of the Nation's Electricity System"
- "FERC-NERC-RE Joint Review of Restoration and Recovery Plans"- "Planning Restoration Absent SCADA and EMS (PRASE)"
- Department of Energy "Staff Report to the Secretary on Electricity Markets and Reliability," NOPR, and FERC

Common Themes

- Define and categorize threats, events and probabilities
- Communication and Information Sharing
- Cross Sector OT and IT Exercises-understand Critical Infrastructure Interdependencies
- Training and cross training
- Tools and Technology (manual override, IT patching)
- Operation in a reduced state
- Metrics and post mortem evaluations
- Align Standards, Practices, Incentives, and Investment with Security Goals (regulators and ratepayers)
- Coordination with law enforcement
- Effects of increased DER on reliability and restoration
- Maintaining the necessary level of Essential Reliability Services

“Intelligence is the ability to adapt to change.”- Stephen Hawking

Questions or Comments ?

2017 Standard Grading Summary

Standard | Requirement		OC	PC	RE	NERC	Avg.	Max Dif	OC	PC	RE	NERC	Avg.	Max Dif
		Content Questions						Quality Questions					
BAL-003-1.1	R1	3	3	2	3	2.75	**1**	13	13	13	13	13	**0**
BAL-003-1.1	R2	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
BAL-003-1.1	R3	3	2	3	3	2.75	**1**	13	13	13	13	13	**0**
BAL-003-1.1	R4	3	2	3	3	2.75	**1**	13	13	13	13	13	**0**
COM-001-2.1	R1	3	2	3	3	2.75	**1**	13	11	13	13	12.5	**2**
COM-001-2.1	R2	3	2	3	3	2.75	**1**	13	12	13	13	12.75	**1**
COM-001-2.1	R3	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R4	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R5	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R6	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R7	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R8	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-001-2.1	R9	3	3	3	3	3.00	**0**	11	13	13	13	12.5	**2**
COM-001-2.1	R10	3	3	3	3	3.00	**0**	12	13	13	13	12.75	**1**
COM-001-2.1	R11	3	3	2	3	2.75	**1**	13	13	10	13	12.25	**3**
COM-002-4	R1	3	3	2	3	2.75	**1**	11	13	13	13	12.5	**2**
COM-002-4	R2	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-002-4	R3	3	3	3	3	3.00	**0**	13	13	13	13	13	**0**
COM-002-4	R4	3	3	3	3	3.00	**0**	13	13	12	13	12.75	**1**
COM-002-4	R5	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
COM-002-4	R6	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
COM-002-4	R7	3	3	3	3	3.00	**0**	12	13	12	13	12.5	**1**
FAC-001-2	R1	3	3	2	3	2.75	**1**	13	10	13	13	12.25	**3**
FAC-001-2	R2	3	3	3	3	3.00	**0**	13	10	13	13	12.25	**3**
FAC-001-2	R3	3	3	3	3	3.00	**0**	13	10	12	13	12	**3**
FAC-001-2	R4	3	3	3	3	3.00	**0**	13	10	11	13	11.75	**3**
FAC-002-2	R1	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R2	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R3	3	2	2	3	2.50	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R4	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
FAC-002-2	R5	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
IRO-009-2	R1	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R2	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R3	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
IRO-009-2	R4	3	3	3	3	3.00	**0**	13	12	13	13	12.75	**1**
MOD-032-1	R1	3	2	1	2	2.00	**2**	13	13	11	13	12.5	**2**
MOD-032-1	R2	3	2	2	2	2.25	**1**	13	13	13	13	13	**0**
MOD-032-1	R3	3	2	2	2	2.25	**1**	13	13	13	13	13	**0**
MOD-032-1	R4	3	2	3	3	2.75	**1**	13	13	12	13	12.75	**1**
TPL-001-4	R1	3	3	3	3	3.00	**0**	13	13	12	13	12.75	**1**
TPL-001-4	R2	3	3	2	3	2.75	**1**	13	13	10	13	12.25	**3**
TPL-001-4	R3	3	2	3	3	2.75	**1**	13	11	10	13	11.75	**3**
TPL-001-4	R4	3	2	3	3	2.75	**1**	13	11	11	13	12	**2**
TPL-001-4	R5	3	3	3	3	3.00	**0**	13	13	11	13	12.5	**2**
TPL-001-4	R6	3	3	3	3	3.00	**0**	13	13	11	13	12.5	**2**
TPL-001-4	R7	3	3	3	3	3.00	**0**	13	13	10	13	12.25	**3**
TPL-001-4	R8	3	3	2	3	2.75	**1**	13	13	11	13	12.5	**2**

Standard Number	Requirement Number	Text of Requirement *(if text is incomplete, please use entire requirement pasted on NERC.com)*	Supports a Reliability Objective (as defined by the Reliability Principles) (Yes or No)	Meets the Paragraph 81 criteria* (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included or is there a gap?	Quality Questions from the Standards Independent Experts Report Q4 (Yes or No) Should the requirement stand alone or, is it or should it be consolidated with other standards?	Q5 (Yes or No) Is it written as a results-based standard (RBS) requirement (states what, not prescriptive, capability) and does it follow the VRS format (e.g., sub-requirement structure)?	Q6 (Yes or No) Is it technologically neutral?	Q7 (Yes or No) Are the expectations for each function clear?	Q8 (Yes or No) Does the requirement align with the purpose?	Q9 (Yes or No) Is it a higher solution than the lowest common denominator?	Q10 (Yes or No) Is it measurable?	Q11 (Yes or No) Does it have a technical basis in engineering and operations?	Q12 (Yes or No) Is it complete and self-contained?	Q13 (Yes or No) Is the language clear and direct, not contain ambiguous or outdated terms?	Q14 (Yes or No) Can it be practically implemented?	Q15 (Yes or No) Does it use consistent terminology?	Q16 (Yes or No) Is the standard used effective in achieving the reliability purpose or objective of the Standard and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-12	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation. The Frequency Response Obligation for a Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High][Time Horizon:Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Balancing Authorities and groups of BAs are the logical place to put this obligation.
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall maintain a Frequency Bias Setting that is, to the extent practical, equal to Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor:Medium][Time Horizon: Operations Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	This is the essence of coordinated frequency operations in a multiple BA interconnect.
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: [Risk Factor: Medium][Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when frequency varies from 60 Hz by more than +/- 0.036 Hz.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Necessary to identify bounds for variable frequency bias.
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, or order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: [Risk Factor: Medium][Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Technical description of the requirements allowing overlap regulation. This wouldn't be necessary if overlap regulation were not allowed.
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High][Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R4	R4: Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R4.1.: Its Reliability Coordinator. R4.2.: Each Balancing Authority within its Transmission Operator Area. R4.3.: Each adjacent Transmission Operator synchronously connected. R4.4.: Each adjacent Transmission Operator asynchronously connected.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each adjacent Balancing Authority.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R6	R6: Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon:Real-time Operations]. R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I was on this SDT. It does feel very administrative and unduly burdensome as a standard, when a simple guide that says that you ought to back up critical communication systems would be sufficient.
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]. R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Note: I was on this SDT. We wanted to put this into certification, but FERC's opinion at the time was that registration wasn't enforceable.
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	13	This could easily be a guide. The testing of backup communications presumes that the primary communications medius is functional - so I doubt this to be a Medium Risk and it is overly prescriptive when the only point is to make sure your backup comms are functioning.
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	This one is a necessary requirement in a mandatory compliance environment, but the time limits are arbitrary and that creates unnecessary grief. 31 minutes, an hour, both of these could be acceptable equipment outage time limits.
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified by the Distribution Provider or Generator Operator, within 60 minutes of the detection of the failure, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	This could easily be a guide. Just tell them to contact their BA/TOP and works something out as a backup (cell phone or something similar.)
COM-002-4	R1	R1: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall develop documented communications protocols for its operating personnel that issue and receive Operating Instructions. The protocols shall, at a minimum: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] R1.1.: Require its operating personnel that issue oral or oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations. R1.2.: Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Confirm the receiver's response if the repeated information is correct. • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. R1.3.: Require its operating personnel that issue oral two-party, person-to-person Operating Instruction to take one of the following actions: • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction. R1.4.: Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. R1.5.: Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification. R1.6.: Specify the nomenclature for Transmission interface Elements and Transmission Interface Facilities when issuing an oral or written Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	13	This never should have included three part communications in the requirement. The English part is okay. Three part should have been a guide and strongly encouraged. FERC Lowered this requirement during the SDT. What they did not understand is that this is only a problem during some other requirement violation, not at any other time. Publishing a guide and enforcing the other, core reliability requirements with extra emphasis when they are violated in part by communication issues is a better approach. We've elevated mundane speech and consequently deemphasized the important speech.
COM-002-4	R2	R2: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Realtime operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to that individual operator issuing an Operating Instruction. [Violation Risk Factor: Low][Time Horizon: Long-term Planning]	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R3	R3: Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R4	R4: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: [Violation Risk Factor:Medium][Time Horizon: Operations Planning] R4.1.: Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, and provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols. R4.2.: Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	Governs emergencies - okay here.
COM-002-4	R5	R5: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6). • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
COM-002-4	R6	R6: Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
COM-002-4	R7	R7: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. [Violation Risk Factor:High][Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	No	3	12	Should have been a guide.
FAC-001-2	R1	R1: Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1. generation Facilities; R1.2.: transmission Facilities; and R1.3. end-user Facilities.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R2	R2: Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an Agreement to conduct a study on the reliability impact of interconnecting a third party Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R3	R3: Each Transmission Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R3.1.: Procedures for coordinated studies of new or materially modified existing interconnections and their impacts on affected system(s). R3.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-001-2	R4	R4: Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R4.1.: Procedures for coordinated studies of new interconnections and their impacts on affected system(s). R4.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of transmission Facilities or electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s); R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Owner planning criteria, and Facility interconnection requirements; R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.2-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	I wonder about why we need this series of standards while FERC also has a LGIA and SGIA?
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding): [Violation Risk Factor: Medium] [Time Horizon: Operations Planning or Same Day Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's Tv.	Yes	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R3	R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [ViolationRisk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in the values identified by different Reliability Coordinators for the responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R1	R1:Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] R1.1.: The data listed in Attachment 1; R1.2.: Specifications of the following items consistent with procedures for building the interconnection-wide case(s): R1.2.1.: Data format; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R2	R2: Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider in the Planning Coordinator's area, and each of its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1 for data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R3	R3: Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [Timehorizon: Long-term Planning]	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R1	R1: Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with the data used for the Planning Assessment, the MOD-032 and MOD-033 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R1.1.: System models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. R1.1.3.: New planned Facilities and changes to existing Facilities R1.1.4.: Real and reactive Load forecasts R1.1.5.: Known commitments for Firm Transmission Service and Interchange R1.1.6.: Resource (supply or demand side) required for Load	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R2	Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady-state analysis, short-circuit analysis, and Stability analysis. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady-state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions: R2.1.1.: System peak Load for either Year One or year two, and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: P1 events in Table 1, with no Contingency modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. R2.1.4.: For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response: • Generator output level and Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.•Controllable Loads and Demand Side Management. • Duration or timing of known Transmission outages. R2.2.5.: When an entity's bank equipment regularly counts near 0 in the unavailability of	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R3	and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizon portions of the steady-state, Part 3.1.1 and 3.1.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R3.1.: Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4. R3.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.3. R3.3.: Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: R3.3.2.1.: Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum voltage ride-through capability. Include in the assessment any assumptions made. R3.3.2.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2.: Simulate the expected automatic operation of existing and planned device designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. R3.4.: Document assumptions, and summarize steady-state, dynamics, and short-circuit analysis results on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. R3.4.1.: The Planning Coordinator and Transmission Planner shall coordinate with adjacent	Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R4	Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R4.1.: Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4. R4.1.1.: For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. R4.1.2.: For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.3. R4.3.: Contingency analyses

TPL-001-4	R6	R6: Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			
TPL-001-4	R7	R7: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			
TPL-001-4	R8	R8: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability need and that submits a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13			

Standard Number	Requirement Number	Text of Requirement *(if text is incomplete, please cut entire requirement pasted on NERC.com)*	Supports a Reliability Objective (as defined by the Reliability Principles)	Meets the Paragraph 81 criteria? (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included in them a gap?	Should the requirement stand alone as it is or should it be combined with other standards?	Is it: A) effect vs a multi-tiered standard (R6); requirement (performance, risk (prevention) or capability) and does it follow the NRS format (e.g., sub-requirement structure)?	Is it technologically neutral?	Are the expectations for each function clear?	Does the requirement align with the purpose?	Is it a higher solution than the lowest common denominator?	Is it measurable?	Does it have a technical basis in engineering and operations?	Is it complete and self-contained?	Is the language clear and does not contain ambiguous or outdated terms?	Can it be practically implemented?	Does it use consistent terminology?	Is the Standard cost effective in achieving the reliability purpose? Have you considered the cost and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-12	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High] [Time Horizon Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor: Medium] [Time Horizon: Operations Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall implement a variable Frequency Bias Setting that is: [Risk Factor: Medium] [Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	There was a confusion on the interpretation of applicability on Interconnection versus Area
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, by one of the following methods: either: [Risk Factor: Medium] [Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO; or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	There was a confusion on the interpretation of applicability on Interconnection versus Area
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	2	11	ICC is too broadly interpreted, guidance should show acceptable examples, not generically applied
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	12	RCs need to be directed to include communications to other RCs in other Interconnections where appropriate. Single entity RC/Interconnections are proof of this.
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R13 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R4	R4: Each Transmission Operator that designates an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R4.1.: Each Balancing Authority within its Transmission Operator Area. R4.2.: Each adjacent Transmission Operator synchronously connected. R4.3.: Each adjacent Transmission Operator asynchronously connected.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each Adjacent Balancing Authority.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R6	R6: Each Balancing Authority that designates an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R11 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Alternative Interpersonal Communication capability at least once each calendar month. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations, Same-day Operations]	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations].	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impacts of new interconnections, new generation Facilities, and materially modified existing and (2) materially modifying existing interconnections of generators, transmission, and electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Planner criteria, and Facility Interconnection Requirements resulting from; R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	The applicability is not clear as it may require entities to duplicate work of one another. Suggest - PC in coordination with the TP, instead of saying PC and TP. Also, when the requirement specifies TP or PC, what if the other doesn't get told.
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity, seeking to interconnect new transmission Facilities, or to materially modify existing or materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including load shedding). [Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Real-time Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's Tv.	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-008
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-009
IRO-009-2	R3	R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's Tv, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-010
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and Tv in instances where there is a difference in an IROL or its Tv between Reliability Coordinators that are responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	12	Where appropriate, this standard should be looked at to consolidate with IRO-011
MOD-032-1	R1	R1.Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short-circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]: R1.1.: The data listed in Attachment 1. R1.2.: Specifications of the following items consistent with procedures for building the Interconnection-wide case(s): R1.2.1.: Data format; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
MOD-032-1	R2	R2. Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short-circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
MOD-032-1	R3	R3. Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the notifying Planning Coordinator or Transmission Planner as follows. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard

MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [Timeframe: Long-term Planning]	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	2	13	ERO needs to be dropped from the applicability of the standard
TPL-001-4	R1	R1: Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items required by other Requirements of this standard. The models shall represent System conditions. This establishes Category P0 as the normal System condition in Table 1 [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R1.1.: System models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. R1.1.3.: New planned Facilities and changes to existing Facilities R1.1.4.: Real and reactive Load forecasts R1.1.5.: Known commitments for firm Transmission Service and Interchange R1.1.6.: Resources (supply or demand-side) required for Load	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R2	Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R1, Part 2.6), document assumptions, and document summarized results of the steady state analysis, short circuit analysis, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to address the following periods: R2.1.1.: System peak Load for either Year One or year two, and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. R2.1.4.: For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, the Planning Assessment shall model and document the conditions and system topology assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a reasonable change in System response: • Real and reactive forecasted Load. • Expected transfers. • Expected in-service status of Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.•ICControllable Loads and Demand Side Management. • Duration or timing of known Transmission outages. R2.1.5.: When an entity's spare-equipment strategy could result in the unavailability of	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R3	and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R3.1.: Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.3. R3.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5. R3.3.: Contingency analysis for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analysis shall include the impact of subsequent: R3.3.1.1.: Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.1.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2.: Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, static var devices, and switched shunts. [Violation Risk Factor: Medium] R3.4.: Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. R3.4.1.: The Planning Coordinator and Transmission Planner shall coordinate with adjacent	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	no	2	11	The question here is in the conduct of all extreme cases being measured. Is it all necessary?
TPL-001-4	R4	Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analysis listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R4.1.: Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.3. R4.1.1.: For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. R4.1.2.: For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system element other than the generating unit and its directly connected facilities. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. R4.3.: Contingency analysis for Requirement R4, Parts 4.1 and 4.2 shall: R4.3.1.: Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analysis shall include the impact of subsequent: R4.3.1.1.: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized. R4.3.1.2.: Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	Yes	Yes	Yes	Yes	Yes	no	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	no	Yes	no	2	11	The question here is in the conduct of all extreme cases being measured. Is it all necessary?
TPL-001-4	R5	R5: Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. These criteria shall include, but are not limited to, a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R6	R6: Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R7	R7: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identifyeach entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon:Long-term Planning]	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	
TPL-001-4	R8	R8: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability-related need and submits a written request for information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1.: If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	3	13	

| Number | Title | Name | Yes/No/Abstain | Yes/No/Abstain | Yes/No/Abstain

Standard Number	Requirement Number	Text of Requirement *If text is incomplete, please cut entire requirement posted on NERC.com*	Supports a Reliability Objective (as defined by the Reliability Principles) (Yes or No)	Meets the Paragraph 81 criteria? (Yes or No)	Appropriate as a guide rather than a standard? (Yes or No)	Content Questions from the Standards Independent Experts Report Q1 (Yes or No) Is the content of the requirement technically correct, including identifying who does what and when?	Q2 (Yes or No) Are the correct functional entities identified?	Q3 (Yes or No) Are the appropriate actions, for which there should be accountability, included or is there a gap?	Quality Questions from the Standards Independent Experts Report Q4 (Yes or No) Should the requirement stand alone or is it more appropriate with other standards?	Q5 (Yes or No) Is it worthy of a metric (i.e. level of performance, risk prevention) or capability and does it follow the 'KBL for'or e.g., 'sub-requirement structure'?	Q6 (Yes or No) Is it technologically neutral?	Q7 (Yes or No) Are the expectations for each function clear?	Q8 (Yes or No) Does the requirement align with the purpose?	Q9 (Yes or No) Is it a higher solution than the lowest common denominator?	Q10 (Yes or No) Is it measurable?	Q11 (Yes or No) Does it have a technical basis in engineering and operations?	Q12 (Yes or No) Is it complete and self-contained?	Q12A (Yes or No) Is the language clear and does not contain ambiguous or outdated terms ?	Q13 (Yes or No) Can it be practically implemented?	Q14 (Yes or No) Does it use consistent terminology?	Q15 (Yes or No) Is the Standard cost effective in achieving the reliability purpose or mitigating the risk identified and mitigating the risk to the BES?	Content Score 0-3	Quality Score 0-13	Comment/Rationale
BAL-003-1.1	R1	R1: Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is maintained by each FRSG and Balancing Authority to support Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. [Risk Factor: High][Time Horizon: Real-time Operations].	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R2	R2: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, or a documented local FRO annually filed with the ERO, on or before the date specified by the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. [Risk Factor:Medium][Time Horizon: Operations Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R3	R3: Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall implement a variable Frequency Bias Setting that is: [Risk Factor: Medium] [Time Horizon: Operations Planning] R3.1: Less than zero at all times, and R3.2: Equal to or more negative than its Frequency Response Obligation when frequency varies from 60 Hz by more than +/- 0.036 Hz.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
BAL-003-1.1	R4	R4: Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: [Risk Factor: Medium][Time Horizon: Operations Planning] • The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or • The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R1	R1: Each Reliability Coordinator shall have Interpersonal Communication capability with the following entities (unless the Reliability Coordinator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R1.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R1.2.: Each adjacent Reliability Coordinator within the same Interconnection.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R2	R2: Each Reliability Coordinator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High][Time Horizon: Real-time Operations] R2.1.: All Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. R2.2.: Each adjacent Reliability Coordinator within the same Interconnection.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R3	R3: Each Transmission Operator shall have Interpersonal Communication capability with the following entities (unless the Transmission Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R3.1.: Its Reliability Coordinator. R3.2.: Each Balancing Authority within its Transmission Operator Area. R3.3.: Each Distribution Provider within its Transmission Operator Area. R3.4.: Each Generator Operator within its Transmission Operator Area. R3.5.: Each adjacent Transmission Operator synchronously connected. R3.6.: Each adjacent Transmission Operator asynchronously connected.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R4	R4: Each Transmission Operator shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R4.1.: Its Reliability Coordinator. R4.2.: Each Balancing Authority within its Transmission Operator Area. R4.3.: Each adjacent Transmission Operator synchronously connected. R4.4.: Each adjacent Transmission Operator asynchronously connected.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R5	R5: Each Balancing Authority shall have Interpersonal Communication capability with the following entities (unless the Balancing Authority detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R5.1.: Its Reliability Coordinator. R5.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R5.3.: Each Distribution Provider within its Balancing Authority Area. R5.4.: Each Generator Operator that operates Facilities within its Balancing Authority Area. R5.5.: Each Adjacent Balancing Authority.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R6	R6: Each Balancing Authority shall designate an Alternative Interpersonal Communication capability with the following entities: [Violation Risk Factor: High] [Time Horizon: Real-time Operations] R6.1.: Its Reliability Coordinator. R6.2.: Each Transmission Operator that operates Facilities within its Balancing Authority Area. R6.3.: Each Adjacent Balancing Authority.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R7	R7: Each Distribution Provider shall have Interpersonal Communication capability with the following entities (unless the Distribution Provider detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations] R7.1.: Its Balancing Authority. R7.2.: Its Transmission Operator.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R8	R8: Each Generator Operator shall have Interpersonal Communication capability with the following entities (unless the Generator Operator detects a failure of its Interpersonal Communication capability in which case Requirement R10 shall apply): [Violation Risk Factor: High] [Time Horizon: Real-time Operations]. R8.1.: Its Balancing Authority. R8.2.: Its Transmission Operator.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R9	R9: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall test its Interpersonal Communication capability required by R1, R2, R3, R4, R5, R6, R7, and R8. If the test is unsuccessful, the responsible entity shall initiate action to repair or designate a replacement Alternative Interpersonal Communication capability within 2 hours. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations, Same-day Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-001-2.1	R10	R10: Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall notify entities as identified in Requirements R1, R3, and R5, respectively within 60 minutes of the detection of a failure of its Interpersonal Communication capability that lasts 30 minutes or longer. [Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	For consistency with VAR-002, should notification be made immediately of any failure of communication lasting greater than 30 minutes?
COM-001-2.1	R11	R11: Each Distribution Provider and Generator Operator that detects a failure of its Interpersonal Communication capability shall consult each entity affected by the failure, as identified in Requirement R7 for a Distribution Provider or Requirement R8 for a Generator Operator, to determine a mutually agreeable action for the restoration of its Interpersonal Communication capability. [Violation Risk Factor: Medium][Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	For consistency with VAR-002, should notification be made immediately of any failure of communication lasting greater than 30 minutes?
COM-002-4	R1	R1: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall have communications (voice and data, redundant and diverse) facilities to issue and receive Operating Instructions. The protocols shall, at a minimum: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] R1.1.: Require its operating personnel that issue and receive oral or written Operating Instruction to use the English language, unless agreed to otherwise. An alternate language may be used for internal operations. R1.2.: Require its operating personnel that issue an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Confirm the receiver's response if the repeated information is correct. • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver. • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver. R1.3.: Require its operating personnel that receive an oral two-party, person-to-person Operating Instruction to take one of the following actions: • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction. R1.4.: Require its operating personnel that issue a written or oral single-party to multiple-party burst Operating Instruction to confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. R1.5.: Specify the instances that require time identification when issuing an oral or written Operating Instruction and the format for that time identification. R1.6.: Specify the facilities where the Transmission Interface Elements and Transmission Interface Facilities which issuing an oral or written Operating Instruction	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R2	R2: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall conduct initial training for each of its operating personnel responsible for the Realtime operation of the interconnected Bulk Electric System on the documented communications protocols developed in Requirement R1 prior to the individual operator's being assigned operating duties. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does verifying initial training for well-seasoned personnel create challenges?
COM-002-4	R3	R3: Each Distribution Provider and Generator Operator shall conduct initial training for each of its operating personnel who can receive an oral two-party, person-to-person Operating Instruction prior to that individual operator receiving an oral two-party, person-to-person Operating Instruction to either: [Violation Risk Factor: Low][Time Horizon: Long-term Planning] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does verifying initial training for well-seasoned personnel create challenges?
COM-002-4	R4	R4: Each Balancing Authority, Reliability Coordinator, and Transmission Operator shall at least once every twelve (12) calendar months: [Violation Risk Factor:Medium][Time Horizon:Operations Planning] R4.1.: Assess adherence to the documented communications protocols in Requirement R1 by its operating personnel that issue and receive Operating Instructions, provide feedback to those operating personnel and take corrective action, as deemed appropriate by the entity, to address deviations from the documented protocols. R4.2.: Assess the effectiveness of its documented communications protocols in Requirement R1 for its operating personnel that issue and receive Operating Instructions and modify its documented communication protocols, as necessary.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R5	R5: Each Balancing Authority, Reliability Coordinator, and Transmission Operator that issues an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Confirm the receiver's response if the repeated information is correct (in accordance with Requirement R6). • Reissue the Operating Instruction if the repeated information is incorrect or if requested by the receiver, or • Take an alternative action if a response is not received or if the Operating Instruction was not understood by the receiver.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R6	R6: Each Balancing Authority, Distribution Provider, Generator Operator, and Transmission Operator that receives an oral two-party, person-to-person Operating Instruction during an Emergency, excluding written or oral single-party to multiple-party burst Operating Instructions, shall either: [Violation Risk Factor: High][Time Horizon: Real-time Operations] • Repeat, not necessarily verbatim, the Operating Instruction and receive confirmation from the issuer that the response was correct, or • Request that the issuer reissue the Operating Instruction.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
COM-002-4	R7	R7: Each Balancing Authority, Distribution Provider, and Transmission Operator that issues a written or oral single-party to multiple-party burst Operating Instruction during an Emergency shall confirm or verify that the Operating Instruction was received by at least one receiver of the Operating Instruction. [Violation Risk Factor:High][Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R1	R1: Each Transmission Owner shall document Facility interconnection requirements, update them as needed, and make them available upon request. Each Transmission Owner's Facility interconnection requirements shall address interconnection requirements for: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1.: Generation Facilities, and R1.2.: transmission Facilities, and R1.3.: end-user Facilities.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R2	R2: Each applicable Generator Owner shall document Facility interconnection requirements and make them available upon request within 45 calendar days of full execution of an interconnection agreement or a modification to existing interconnection agreement to a Facility to the Generator Owner's existing Facility that is used to interconnect to the Transmission system. [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R3	R3: Each Transmission Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R3.1.: Procedures for coordinated joint studies of new or materially modified existing interconnections and their impacts on affected system(s). R3.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new or materially modified existing interconnections.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-001-2	R4	R4: Each applicable Generator Owner shall address the following items in its Facility interconnection requirements: [Violation Risk Factor: Lower] [Time Horizon: Long-Term Planning] R4.1.: Procedures for coordinated joint studies of new interconnections and their impacts on affected system(s). R4.2.: Procedures for notifying those responsible for the reliability of affected system(s) of new interconnections.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R1	R1: Each Transmission Planner and each Planning Coordinator shall study the reliability impact of: (i) interconnecting new generation, transmission, or electricity end-user Facilities and (ii) materially modifying existing interconnections of generation, transmission, or electricity end-user Facilities. The following shall be studied: [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R1.1.: The reliability impact of the new interconnection, or materially modified existing interconnection, on affected system(s). R1.2.: Adherence to applicable NERC Reliability Standards, regional and Transmission Planner criteria, and applicable Nuclear Plant Interface Requirements (NPIRs). R1.3.: Steady-state, short-circuit, and dynamics studies, as necessary, to evaluate system performance under both normal and contingency conditions; and R1.4.: Study assumptions, system performance, alternatives considered, and coordinated recommendations. While these studies may be performed independently, the results shall be evaluated and coordinated by the entities involved.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R2	R2: Each Generator Owner seeking to interconnect new generation Facilities, or to materially modify existing interconnections of generation Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R3	R3: Each Transmission Owner, each Distribution Provider, and each Load-Serving Entity seeking to interconnect new transmission Facilities or electricity end-user Facilities, or to materially modify existing interconnections of transmission Facilities or electricity end-user Facilities, shall coordinate and cooperate on studies with its Transmission Planner or Planning Coordinator, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R4	R4: Each Transmission Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested new or materially modified interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	
FAC-002-2	R5	R5: Each applicable Generator Owner shall coordinate and cooperate with its Transmission Planner or Planning Coordinator on studies regarding requested interconnections to its Facilities, including but not limited to the provision of data as described in R1, Parts 1.1-1.4. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
IRO-009-2	R1	R1: For each IROL (in its Reliability Coordinator Area) that the Reliability Coordinator identifies one or more days prior to the current day, the Reliability Coordinator shall have one or more Operating Processes, Procedures, or Plans that identify actions the Reliability Coordinator shall take or actions the Reliability Coordinator shall direct others to take (up to and including Emergency procedures): [Violation Risk Factor: High] [Time Horizon: Operations Planning or Same-Day Operations] R1.1.: That can be implemented in time to prevent the identified IROL exceedance. R1.2.: To mitigate the magnitude and duration of an IROL exceedance such that the IROL exceedance is relieved within the IROL's T_V.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R2	R2: Each Reliability Coordinator shall initiate one or more Operating Processes, Procedures, or Plans (not limited to the Operating Processes, Procedures, or Plans developed for Requirement R1) that are intended to prevent an IROL exceedance, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R3	R3: Each Reliability Coordinator shall act or direct others to act so that the magnitude and duration of an IROL exceedance is mitigated within the IROL's T_V, as identified in the Reliability Coordinator's Real-time monitoring or Real-time Assessment. [ViolationRisk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
IRO-009-2	R4	R4: Each Reliability Coordinator shall operate to the most limiting IROL and T_V in instances where there is a difference in an IROL or its T_V between Reliability Coordinators that are responsible for that Facility (or group of Facilities). [Violation Risk Factor: High] [Time Horizon: Real-time Operations]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Does it adequately cover the right entities; e.g., should it include Adjacent RC, and perhaps Transmission Operator?
MOD-032-1	R1	R1:Each Planning Coordinator and each of its Transmission Planners shall jointly develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R1.1.: The data listed in Attachment 1. R1.2.: Specifications of the following items consistent with procedures for building the interconnection-wide case(s): R1.2.1: Data formats; R1.2.2.: Level of detail to which equipment shall be modeled; R1.2.3.: Case types or scenarios to be modeled; and R1.2.4.: A schedule for submission of data at least once every 13 calendar months. R1.3.: Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.	YES	YES	NO	YES	No	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	R2	R2: Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to its Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient. [Violation Risk Factor: Medium] [Time Horizon:Long-term Planning]	YES	YES	NO	YES	NO	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	R3	R3: Upon receipt of written notification from its Planning Coordinator or Transmission Planner regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall provide to the notifying Planning Coordinator or Transmission Planner as follows: [Violation Risk Factor: Lower] [Time Horizon: Long-term Planning] R3.1.: Provide either updated data or an explanation with a technical basis for maintaining the current data. R3.2.: Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying Planning Coordinator or Transmission Planner.	YES	YES	NO	YES	NO	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	2	11	LSE is no longer in Registry.
MOD-032-1	R4	R4: Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the Electric Reliability Organization (ERO) or its designee to support creation of the interconnection-wide case(s) that includes the Planning Coordinator's planning area. [Violation Risk Factor: Medium] [TimeHorizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	
TPL-001-4	R1	R1: Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R1.1.: Models shall represent: R1.1.1.: Existing Facilities R1.1.2.: Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. R1.1.3.: New planned Facilities and changes to existing Facilities R1.1.4.: Real and reactive Load forecasts R1.1.5.: Known commitments for firm Transmission Service and Interchange R1.1.6.: Resources (supply or demand side) required for Load	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should models capture adjacent Transmission Planner area?
TPL-001-4	R2	R2: Each Transmission Planner and Planning Coordinator shall perform an annual Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies, as allowed in Requirement R2, Part 2.4; document assumptions and document summarized results of the steady-state analyses, short circuit analysis, and Stability analyses. [Violation Risk Factor: High] [Time Horizon: Long-term Planning] R2.1.: For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.4. Qualifying studies need to include the following conditions: R2.1.1.: System Peak Load for one of the five years and for year five. R2.1.2.: System Off-Peak Load for one of the five years. R2.1.3.: P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.2.2, under those System peak or Off-Peak conditions when known outages are scheduled. R2.1.4.: For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the base assumptions used in the models listed in Requirement R1. The sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrates a measurable change in System response: • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.•Uncontrollable Loads and generation. • Duration or timing of known Transmission outages. R2.1.5.: When an entity's spare equipment strategy could result in the unavailability of	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should adjacent system be monitored for reliability issues and model outages in adjacent planning area?
TPL-001-4	R3	R3: Each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R3.1.: Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4. R3.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5. R3.3.: Contingency analysis for Requirement R3, Parts 3.1 & 3.2 shall: R3.3.1.: Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analysis shall include the impact of subsequent: R3.3.2.: Tripping of Transmission elements where relay loadability limits are exceeded. R3.3.2: Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area, such as generator voltage regulators, load tap changing transformers, and switched capacitors and inductors. R3.4.: Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should contingencies from the adjacent planning models be included?
TPL-001-4	R4	R4: Each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R4.1.: Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4. R4.1.1.: For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism. R4.1.2.: For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities. R4.1.3.: For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner. R4.2.: Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5. R4.3.: Contingency analysis for Requirement R4, Parts 4.5 and 4.2 shall : R4.3.1.: Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analysis shall include the impact of subsequent: R4.3.1.1.: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a fault where high speed reclosing is utilized. R4.3.2.2.: Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed minimum generator voltage ride through capability. Include in the assessment any assumptions made.	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	Yes	YES	YES	YES	YES	YES	YES	3	13	Should contingencies from the adjacent planning models be included?
TPL-001-4	R5	R5: Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES	YES	NO	YES	YES	YES	YES	YES	YES	YES	YES	YES	No	YES	YES	YES	YES	YES	YES	3	13	Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-001-2.

TPL-001-4	R6	R6: Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2.
TPL-001-4	R7	R7: Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2.
TPL-001-4	R8	R8: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and the receiving entity shall have a reliability need if it cannot duplicate, using publicly available models, the results of the Planning Assessment. The receiving entity may submit a written request for the information within 30 days of such a request. [Violation Risk Factor: Medium] [Time Horizon: Long-term Planning] R8.1: If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	YES		YES		NO		YES		YES		YES		YES		YES		YES		YES		YES		YES		YES	3		Should most limiting criteria be included? Reference for this would be Requirement R1, Part 1.1.2 of FAC-002-2. Should third-party impact be identified and followed by coordination of study results?

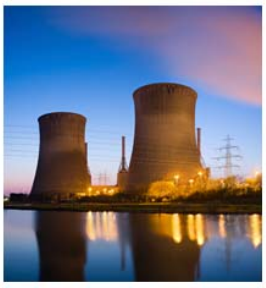
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT Reliability Standards Development Plan

2018-2020

June 2017

RELIABILITY | ACCOUNTABILITY



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Background

The 2017–2019 Reliability Standards Development Plan (RSDP) continued progress toward NERC's goal to develop a stable set of clear, concise, technically sound, and results-based NERC Reliability Standards and to retire requirements that do little to promote reliability. The 2017-2019 RSDP specifically highlighted the importance of the Integration of Variable Generation Task Force and Essential Reliability Services Working Group (ERSWG) recommendations and called for continued communication with the Reliability Issues Steering Committee (RISC) on emerging risks. The 2017-2019 RSDP also indicated that most of the work in the next three years would focus on Periodic Reviews and recognized there may be new or emerging risks identified that would generate new standards development projects. The addition of the Standards Grading Metric in 2016 informs the Periodic Reviews as to the quality and content of the standards.[1]

The 2017-2019 RSDP also recognized the importance of addressing subsequent directives from applicable regulatory authorities including the Federal Energy Regulatory Commission (FERC), Standard Authorization Requests (SARs), and the value of enhanced communication through industry feedback loops. It also stressed that Periodic Reviews and standards development activities would occur at a measured pace, compared to the level of activity and pace of standards development during previous years, and they will be aligned with strategic considerations of reviewing standard families that are interrelated.[2]

As described herein, the 2018-2020 RSDP builds upon the goals of the 2017-2019 RSDP, adding an additional objective of enhanced consideration of cost effectiveness in standards development.

Pursuant to section 310 of the NERC Rules of Procedure, NERC is required to develop and provide to applicable governmental authorities an annual RSDP for Reliability Standards development. Each annual RSDP must include a progress report comparing results achieved to the prior year's RSDP. NERC is required to consider the comments and priorities of the applicable governmental authorities in developing and updating the annual RSDP. NERC also provides the RSDP to the NERC Standards Committee (SC) for review and posts the RSDP for industry comment.

[1] The Periodic Review standing review team will grade the standards. The team includes representatives from NERC, the Regional Entities, and the NERC technical committees. Grading occurs prior to conducting the Periodic Review.

[2] In some cases, a narrower review of a standard will likely be appropriate. For example, there are not necessarily other interrelated standards with FAC-003.

Executive Summary

The 2018–2020 RSDP recognizes the diligent work of the last few years in transforming the body of NERC Reliability Standards into a mature state while shifting its focus to Periodic Reviews, FERC directives, emerging risks, SARs, and the standards grading initiative. The 2018-2020 RSDP also contemplates that the work of the various NERC technical committees and working groups thereunder, may result in one or more SARs and subsequent standards projects.

As with the 2017-2019 RSDP, Periodic Reviews will occur at a measured pace compared to the level of activity and pace of standards development during recent years. Additionally, Periodic Reviews will be aligned with strategic considerations of reviewing standard families that are interrelated. The Standards Grading Metric and "Final Grades for Standards Graded in 2017" (Attachment 1) help to inform the Periodic Reviews as to the quality and content of the standards.[3]

The 2018-2020 RSDP also includes plans for completing the Periodic Reviews initiated in 2016 and 2017, and for commencing additional Periodic Reviews in 2018.

While most of the work in the next three years will focus on Periodic Reviews, there may be new or emerging risks identified that would generate new standards development projects. NERC will continue to seek input and recommendations from the RISC with regard to emerging or potential risks to BES reliability that may require revisions to existing standards or new standards development. To help determine impact of potential risk to BES reliability, NERC will use various feedback mechanisms, including but not limited to, feedback from the Compliance Monitoring and Enforcement Program, RISC profiles, Events Analysis and Compliance violation statistics, as well as any published "Lessons Learned." The Regional Entities also have feedback mechanisms in place to solicit comments from industry and to help identify approaches to meet concerns and provide input to the standards. Standards input will continue to be coordinated with the North American Energy Standards Board as appropriate.

NERC is committed to enhancing and refining cost effectiveness considerations in the standards development process during the 2018-2020 period. For example, during 2016 and 2017, NERC conducted two cost effectiveness pilots.[4] NERC continues to develop and implement its cost effectiveness process, which has been implemented more broadly in standards development and will continue to evolve during this work plan period. Cost effectiveness questions are also part of the Periodic Reviews and SAR process. NERC will continue to look for ways to enhance or refine the review and implementation of cost effectiveness during the standards development process in a way that is productive and does not unduely burden the industry for data and input.

This 2018-2020 RSDP provides insight into standards development activities anticipated at the time of publication, so that stakeholders may make available appropriate resources to accomplish these standards development objectives. Additional activities such as Requests for Interpretation and Regional Variance development may impact the plan. In order to help the industry understand resource requirements for each project, the RSDP now shows time frames and anticipated resources for each project under development.

[3] The Periodic Review standing review team grades the standards prior to conducting Periodic Reviews. The team includes representatives from NERC, the Regions, and NERC technical committees. If there is a recommended change in the standard due to Periodic Review recommendations and subject to the standards development process, the Periodic Review standing review team will re-grade the standard with the revised language.

[4] Information on NERC's cost effectiveness initiative can be found at: http://www.nerc.com/pa/Stand/Pages/CostEffectivenessPilot.aspx.

2017 Progress Report

Pursuant to section 310 of the NERC Rules of Procedure, NERC offers the following progress report on Reliability Standards development in 2017.

FERC Directives

As of June 14, 2017, there are 29 outstanding FERC directives. Additionally, FERC has issued directives pertaining to issues outside of NERC standards. These additional directives are being addressed by the NERC technical committees and other NERC departments (e.g., topics related to reliability assessment, performance analysis, etc.), which are not reflected in this total.

Projects Completed in 2017

The 2017–2019 RSDP identified nine projects initiated in 2017 or continued from 2016. All of the projects listed therein have been completed in 2016 or are planned to be completed in 2017 except for Project 2013-03 Geomagnetic Disturbance Mitigation, Project 2015-09 Establish and Communicate System Operating Limits, Project 2015-10 Single Points of Failure, and Project 2016-02 Modifications to CIP Standards. Additional project information is available on the NERC website on the Standards page.[5]

The following projects have been or are planned to be completed in 2017 (actual and anticipated NERC Board of Trustees (Board) adoption dates are noted)**:**

Projects from the 2017-2019 RSDP

1. Project 2015-08 Emergency Operations – EOP-004, EOP-005, EOP-006, EOP-008 (adopted by the Board in February 2017)
2. Project 2016-01 Modifications to TOP and IRO Standards – TOP-001, IRO-002 (adopted by the Board in February 2017)
3. Project 2016-03 Cyber Security Supply Chain Management – CIP-013-1 (Board adoption expected in August 2017)
4. Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, and PER-004
5. Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards - VAR-001 and VAR-002

[5] As of the date of publication, the subject web page resides at http://www.nerc.com/pa/Stand/Pages/default.aspx.

2018 Projects

Projects Continuing from 2017 into 2018

In determining high, medium, or low priority to designate projects as listed in this RSDP, the following factors were taken into consideration.

1. Outstanding regulatory directives with filing deadlines (High Priority)
2. RISC category rankings of high impact with consideration of probability of occurrence (High or Medium Priority)
3. Potential reliability risk from stakeholders provided through feedback mechanism (High, Medium or Low Priority, based on the risk)
4. Outstanding regulatory directives without regulatory deadlines or "soft directives" such as considerations (High or Medium Priority)
5. Outstanding requirements that are known candidates for retirement (Medium or Low Priority)
6. Any known adverse content and quality assessments (likely Low Priority, as any reliability gaps identified have already been addressed)

High Priority

- Project 2013-03 Geomagnetic Disturbance Mitigation - TPL-007-2 (drafting estimated to be completed by April 1, 2018[6] requiring approximately 11 industry subject matter experts for approximately 120 work hours[7] each for the remaining part of this project)
    - FERC established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 2018
- Project 2016-02: Modifications to CIP Standards (drafting estimated to be completed by May 1, 2018 requiring approximately 10 industry subject matter experts or approximately 75 work hours each for the remaining part of this project)

Medium Priority

- Project 2015-09 Establish and Communicate System Operating Limits- FAC-010, FAC-011, FAC-014 (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 100 work hours each for the remaining part of this project)
- Project 2015-10 Single Points of Failure - TPL-001 (drafting estimated to be completed by April 1, 2018 requiring approximately 10 industry subject matter experts or approximately 60 work hours each for the remaining part of this project)
- 2016-04 Modifications to PRC-025-1 (drafting estimated to be completed by April 1, 2018 requiring approximately 6 industry subject matter experts for approximately 60 work hours each for the remaining part of this project)

Low Priority

- Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards - PER-001, PER-003, and PER-004 (drafting estimated to be completed by April 1, 2018

[6] The "estimated drafting completed by" date is NERC's estimate of the final ballot date.
[7] The "work hours" estimates apply to 2018 only.

requiring approximately 10 industry subject matter experts for approximately 40 work hours each for the remaining part of this project)

- Project 2017-03 FAC-008 Periodic Review (drafting estimated to be completed by August 1, 2018 requiring approximately 10 industry subject matter experts for approximately 100 work hours each for the remaining part of this project)
- Project 2017-04 Periodic Review of Interchange Scheduling and Coodination Standards - INT-004, INT-006, INT-009 and INT-010 (drafting estimated to be completed by August 1, 2018 requiring approximately 10 industry subject matter experts for approximately 80 work hours each for the remaining part of this project)
- Project 2017-05 Periodic Review of NUC-001-3 (drafting estimated to be completed by May 1, 2018 requiring approximately eight industry subject matter experts for approximately 60 work hours each for the remaining part of this project)

Projects Commencing in 2018

At least two Periodic Reviews should commence in 2018.

The following 31 standards will be eligible for periodic review in 2018:

BAL-005-02b	IRO-006-5	MOD-008-1	MOD-030-3	PRC-019-2
BAL-006-2	IRO-008-2	MOD-020-0	MOD-031-2	TOP-002-4
CIP-014-2	IRO-010-2	MOD-025-2	MOD-033-1	TOP-003-3
FAC-003-4	IRO-014-3	MOD-026-1	PER-001-1.1(ii)	
FAC-010-3	IRO-017-1	MOD-027-1	PRC-002-2	
FAC-013-2	MOD-001-1a	MOD-028-2	PRC-015-1	
IRO-001-4	MOD-004-1	MOD-029-2a	PRC-016-1	

Additionally, SARs, emerging risks to the Bulk Power System, and FERC regulatory directives that may occur subsequent to publishing this RSDP may prompt additional projects in 2018.

Standards Grading Metrics

The NERC SC endorsed a grading system for standards as a metric on March 9, 2016. The grading is conducted by the Periodic Review Standing Review Team (PRSRT) as set forth in the Periodic Review process. The PRSRT is comprised of the following:

- SRT chair: SC chair or (or SC chair delegate)
- Operating Committee (OC) chair (or OC chair delegate)
- Planning Committee (PC) chair (or PC chair delegate)
- NERC staff
- Representation from the Regional Entities

The grading metrics include possible scores of 0-3 for quality and 0-13 for content. The set of standards chosen each year for grading, according to the criteria in the above section, will be reviewed and their grading will be used to prioritize and determine the sequence they should enter into the Periodic Review process. At least one industry comment period will take place to allow industry to comment on the grading performed by the PRSRT. The grades, based on the PRSRT and any industry input will be finalized, appended to the RSDP, and used to complete the prioritization each year.

Attachment 1

Final Grades for Standards Graded in 2017 (placeholder)

Standard and Requirement	Content Average	Quality Average

A. Introduction

1. **Title:** Transmission System Planned Performance for Geomagnetic Disturbance Events

2. **Number:** TPL-007-~~1~~2

3. **Purpose:** Establish requirements for Transmission system planned performance during geomagnetic disturbance (GMD) events.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Planning Coordinator with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.2 Transmission Planner with a planning area that includes a Facility or Facilities specified in 4.2;

   4.1.3 Transmission Owner who owns a Facility or Facilities specified in 4.2;

   4.1.4 Generator Owner who owns a Facility or Facilities specified in 4.2.

   4.2. Facilities:

   4.2.1 Facilities that include power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV.

5. **Background:**

   During a GMD event, geomagnetically-induced currents (GIC) may cause transformer hot-spot heating or damage, loss of Reactive Power sources, increased Reactive Power demand, and Misoperation(s), the combination of which may result in voltage collapse and blackout.

6. **Effective Date:**

   See Implementation Plan for TPL-007-~~1~~2

B. Requirements and Measures

R1. Each Planning Coordinator, in conjunction with its Transmission Planner(s), shall identify the individual and joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models ~~and~~, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~, and implementing process(es) to obtain GMD measurement data as specified in this standard. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M1. Each Planning Coordinator, in conjunction with its Transmission Planners, shall provide documentation on roles and responsibilities, such as meeting minutes, agreements, copies of procedures or protocols in effect between entities or between departments of a vertically integrated system, or email correspondence that identifies an agreement has been reached on individual and joint responsibilities for maintaining models ~~and~~,

performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~, and implementing process(es) to obtain GMD ~~M~~measurement ~~D~~data in accordance with Requirement R1.

R2. Each responsible entity, as determined in Requirement R1, shall maintain System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

M2. Each responsible entity, as determined in Requirement R1, shall have evidence in either electronic or hard copy format that it is maintaining System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.

R3. Each responsible entity, as determined in Requirement R1, shall have criteria for acceptable System steady state voltage performance for its System during the ~~benchmark~~ GMD ~~event~~events described in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M3. Each responsible entity, as determined in Requirement R1, shall have evidence, such as electronic or hard copies of the criteria for acceptable System steady state voltage performance for its System in accordance with Requirement R3.

Benchmark GMD Vulnerability Assessment(s)

R4. Each responsible entity, as determined in Requirement R1, shall complete a benchmark GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This benchmark GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

4.1. The study or studies shall include the following conditions:

4.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

4.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

4.2. The study or studies shall be conducted based on the benchmark GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning benchmark GMD event contained in Table 1.

4.3. The benchmark GMD Vulnerability Assessment shall be provided: (i) ~~within 90 calendar days of completion~~ to the responsible entity's Reliability Coordinator,

adjacent Planning Coordinators, and adjacent Transmission Planners~~,~~ within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later.

4.3.1. If a recipient of the benchmark GMD Vulnerability Assessment provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M4. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its benchmark GMD Vulnerability Assessment meeting all of the requirements in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its benchmark GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the benchmark GMD Vulnerability Assessment, whichever is later, ~~within 90 calendar days of completion to its Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and to any functional entity who has submitted a written request and has a reliability-related need~~ as specified in Requirement R4. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its benchmark GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R4.

R5. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the ~~transformer~~benchmark thermal impact assessment of transformers specified in Requirement R6 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

5.1. The maximum effective GIC value for the worst case geoelectric field orientation for the benchmark GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

5.2. The effective GIC time series, GIC(t), calculated using the benchmark GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power

transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 5.1.

M5. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective benchmark GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R5, Part 5.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R6. Each Transmission Owner and Generator Owner shall conduct a benchmark thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater. The benchmark thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- **6.1.** Be based on the effective GIC flow information provided in Requirement R5;
- **6.2.** Document assumptions used in the analysis;
- **6.3.** Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and
- **6.4.** Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.

M6. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its benchmark thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its thermal impact assessment to the responsible entities as specified in Requirement R6.

Rationale for Requirement R7: The proposed requirement addresses directives in Order No. 830 for establishing Corrective Action Plan (CAP) deadlines associated with GMD Vulnerability Assessments. In Order No. 830, FERC directed revisions to TPL-007 such that CAPs are developed within one year from the completion of GMD Vulnerability Assessments (P. 101). Furthermore, FERC directed establishment of implementation deadlines after the completion of the CAP as follows (P. 102):

- Two years for non-hardware mitigation; and

- Four years for hardware mitigation.

The objective of Part 7.4 is to provide awareness to potentially impacted entities when implementation of planned mitigation is not achievable within the deadlines established in Part 7.3.

R7. Each responsible entity, as determined in Requirement R1, that concludes~~,~~ through the benchmark GMD Vulnerability Assessment conducted in Requirement R4~~,~~ that their System does not meet the performance requirements ~~of~~for the steady state planning benchmark GMD event contained in Table 1 shall develop a Corrective Action Plan (CAP) addressing how the performance requirements will be met. The ~~Corrective Action Plan~~CAP shall: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or ~~Special Protection Systems~~Remedial Action Schemes.
- Use of Operating Procedures, specifying how long they will be needed as part of the ~~Corrective Action Plan~~CAP.
- Use of Demand-Side Management, new technologies, or other initiatives.

7.2. ~~Be reviewed in subsequent GMD Vulnerability Assessments until it is determined that the System meets the performance requirements contained in Table 1.~~Be developed within one year of completion of the benchmark GMD Vulnerability Assessment.

7.3. Include a timetable, subject to revision by the responsible entity in Part 7.4, for implementing the selected actions from Part 7.1. The timetable shall:

7.3.1. Specify implementation of non-hardware mitigation, if any, within two years of development of the CAP; and

7.3.2. Specify implementation of hardware mitigation, if any, within four years of development of the CAP.

7.4. Be revised if situations beyond the control of the responsible entity determined in Requirement R1 prevent implementation of the CAP within the timetable for implementation provided in Part 7.3. The revised CAP shall document the following, and be updated at least once every 12 calendar months until implemented:

7.4.1. Circumstances causing the delay for fully or partially implementing the selected actions in Part 7.1;

7.4.2. Description of the original CAP, and any previous changes to the CAP, with the associated timetable(s) for implementing the selected actions in Part 7.1; and

7.4.3. Revisions to the selected actions in Part 7.1, if any, including utilization of Operating Procedures if applicable, and the updated timetable for implementing the selected actions.

~~7.2.~~7.5. Be provided: (i) ~~within 90 calendar days of completion~~development or ~~revision~~ to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the ~~Corrective Action Plan~~CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later.

~~7.2.1.~~7.5.1. If a recipient of the ~~Corrective Action Plan~~CAP provides documented comments on the results, the responsible entity shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M7. Each responsible entity, as determined in Requirement R1, that concludes, through the benchmark GMD Vulnerability Assessment conducted in Requirement R4, that the responsible entity's System does not meet the performance requirements ~~of~~ for the steady state planning benchmark GMD event contained in Table 1 shall have evidence such as dated electronic or hard copies of its ~~Corrective Action Plan~~CAP including timetable for implementing selected actions, as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records or postal receipts showing recipient and date, that it has revised its CAP if situations beyond the responsible entity's control prevent implementation of the CAP within the timetable specified. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its ~~Corrective Action Plan~~CAP or relevant information, if any, (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinator(s), adjacent Transmission Planner(s), and functional entities referenced in the CAP within 90 calendar days of development or revision, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of development or revision, whichever is later,~~within 90 calendar days of its completion~~development or revision to its Reliability Coordinator, ~~adjacent Planning Coordinator(s), adjacent Transmission Planner(s), a functional entity referenced in the Corrective Action Plan~~CAP, ~~and any functional entity that submits~~who ~~has submitted a written request and has a reliability-related need,~~ as specified in Requirement R7. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date,

that it has provided a documented response to comments received on its ~~Corrective Action Plan~~CAP within 90 calendar days of receipt of those comments, in accordance with Requirement R7.

Supplemental GMD Vulnerability Assessment(s)

Rationale for Requirements R8 - R10: The proposed requirements address directives in Order No. 830 for revising the benchmark GMD event used in GMD Vulnerability Assessments (P.44, P47-49). The requirements add a supplemental GMD Vulnerability Assessment based on the supplemental GMD event that accounts for localized peak geoelectric fields.

R8. Each responsible entity, as determined in Requirement R1, shall complete a supplemental GMD Vulnerability Assessment of the Near-Term Transmission Planning Horizon at least once every 60 calendar months. This supplemental GMD Vulnerability Assessment shall use a study or studies based on models identified in Requirement R2, document assumptions, and document summarized results of the steady state analysis. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

8.1. The study or studies shall include the following conditions:

8.1.1. System On-Peak Load for at least one year within the Near-Term Transmission Planning Horizon; and

8.1.2. System Off-Peak Load for at least one year within the Near-Term Transmission Planning Horizon.

8.2 The study or studies shall be conducted based on the supplemental GMD event described in Attachment 1 to determine whether the System meets the performance requirements for the steady state planning supplemental GMD event contained in Table 1.

8.3 If the analysis concludes there is Cascading caused by the supplemental GMD event described in Attachment 1, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

8.4 The supplemental GMD Vulnerability Assessment shall be provided: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, and adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later.

8.4.1 If a recipient of the supplemental GMD Vulnerability Assessment provides documented comments on the results, the responsible entity

shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each responsible entity, as determined in Requirement R1, shall have dated evidence such as electronic or hard copies of its supplemental GMD Vulnerability Assessment meeting all of the requirements in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has distributed its supplemental GMD Vulnerability Assessment: (i) to the responsible entity's Reliability Coordinator, adjacent Planning Coordinators, adjacent Transmission Planners within 90 calendar days of completion, and (ii) to any functional entity that submits a written request and has a reliability-related need within 90 calendar days of receipt of such request or within 90 calendar days of completion of the supplemental GMD Vulnerability Assessment, whichever is later, as specified in Requirement R8. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email notices or postal receipts showing recipient and date, that it has provided a documented response to comments received on its supplemental GMD Vulnerability Assessment within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R9. Each responsible entity, as determined in Requirement R1, shall provide GIC flow information to be used for the supplemental thermal impact assessment of transformers specified in Requirement R10 to each Transmission Owner and Generator Owner that owns an applicable Bulk Electric System (BES) power transformer in the planning area. The GIC flow information shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

9.1. The maximum effective GIC value for the worst case geoelectric field orientation for the supplemental GMD event described in Attachment 1. This value shall be provided to the Transmission Owner or Generator Owner that owns each applicable BES power transformer in the planning area.

9.2. The effective GIC time series, GIC(t), calculated using the supplemental GMD event described in Attachment 1 in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area. GIC(t) shall be provided within 90 calendar days of receipt of the written request and after determination of the maximum effective GIC value in Part 9.1.

M9. Each responsible entity, as determined in Requirement R1, shall provide evidence, such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided the maximum effective supplemental GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area as specified in Requirement R9, Part 9.1. Each responsible entity, as determined in Requirement R1, shall also provide evidence, such as email records, web postings with an electronic notice of posting, or postal

receipts showing recipient and date, that it has provided GIC(t) in response to a written request from the Transmission Owner or Generator Owner that owns an applicable BES power transformer in the planning area.

R10. Each Transmission Owner and Generator Owner shall conduct a supplemental thermal impact assessment for its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater. The supplemental thermal impact assessment shall: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

10.1. Be based on the effective GIC flow information provided in Requirement R9;

10.2. Document assumptions used in the analysis;

10.3. Describe suggested actions and supporting analysis to mitigate the impact of GICs, if any; and

10.4. Be performed and provided to the responsible entities, as determined in Requirement R1, within 24 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.

M10. Each Transmission Owner and Generator Owner shall have evidence such as electronic or hard copies of its supplemental thermal impact assessment for all of its solely and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A per phase or greater, and shall have evidence such as email records, web postings with an electronic notice of posting, or postal receipts showing recipient and date, that it has provided its supplemental thermal impact assessment to the responsible entities as specified in Requirement R10.

GMD Measurement Data Processes

Rationale for Requirements R11 and R12: The proposed requirements address directives in Order No. 830 for requiring responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness (P. 88; P. 90-92). See the Guidelines and Technical Basis section of this standard for technical information.

The objective of Requirement R11 is for entities to obtain GIC data for the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model to inform GMD Vulnerability Assessments. Technical considerations for GIC monitoring are contained in Chapter 6 of the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System* (NERC 2012 GMD Report). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the transformer and measure dc current flowing through the neutral.

The objective of Requirement R12 is for entities to obtain geomagnetic field data for the Planning Coordinator's planning area to inform GMD Vulnerability Assessments.

Magnetometers provide geomagnetic field data by measuring changes in the earth's magnetic field. Sources of geomagnetic field data include:

- Observatories such as those operated by U.S. Geological Survey, Natural Resources Canada, research organizations, or university research facilities.
- Installed magnetometers
- Commercial or third-party sources of geomagnetic field data

Geomagnetic field data for a Planning Coordinator's planning area is obtained from one or more of the above data sources located in the Planning Coordinator's planning area, or by obtaining a geomagnetic field data product for the Planning Coordinator's planning area from a government or research organization. The geomagnetic field data product does not need to be derived from a magnetometer or observatory within the Planning Coordinator's planning area.

~~R8.~~R11. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System model. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M11. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its GIC monitor location(s) and documentation of its process to obtain GIC monitor data in accordance with Requirement R11.

~~R9.~~R12. Each responsible entity, as determined in Requirement R1, shall implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area. *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

M12. Each responsible entity, as determined in Requirement R1, shall have evidence such as electronic or hard copies of its process to obtain geomagnetic field data for its Planning Coordinator's planning area in accordance with Requirement R12.

Table 1 – Steady State Planning GMD Event

Steady State:

a. Voltage collapse, Cascading and uncontrolled islanding shall not occur.

b. Generation loss is acceptable as a consequence of the steady state planning GMD events.

c. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Category	Initial Condition	Event	Interruption of Firm Transmission Service Allowed	Load Loss Allowed
Benchmark GMD Event - GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes[3]	Yes[3]
Supplemental GMD Event - GMD Event with Outages	1. System as may be postured in response to space weather information[1], and then 2. GMD event[2]	Reactive Power compensation devices and other Transmission Facilities removed as a result of Protection System operation or Misoperation due to harmonics during the GMD event	Yes	Yes

Table 1 – Steady State Performance Footnotes

1. The System condition for GMD planning may include adjustments to posture the System that are executable in response to space weather information.
2. The GMD conditions for the benchmark and supplemental planning ~~event~~events are described in Attachment 1~~ (Benchmark GMD Event).~~.
3. Load loss as a result of manual or automatic Load shedding (e.g.~~,~~, UVLS) and/or curtailment of Firm Transmission Service may be used to meet BES performance requirements during studied GMD conditions. The likelihood and magnitude of Load loss or curtailment of Firm Transmission Service should be minimized.

Attachment 1

Calculating Geoelectric Fields for the Benchmark and Supplemental GMD EventEvents

The benchmark GMD event[1] defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. It is composed of the following elements: (1) a reference peak geoelectric field amplitude of 8 V/km derived from statistical analysis of historical magnetometer data; (2) scaling factors to account for local geomagnetic latitude; (3) scaling factors to account for local earth conductivity; and (4) a reference geomagnetic field time series or waveshapewaveform to facilitate time-domain analysis of GMD impact on equipment.

The supplemental GMD event is composed of similar elements as described above, except (1) the reference peak geoelectric field amplitude is 12 V/km over a localized area; and (2) the geomagnetic field time series or waveform includes a local enhancement in the waveform.[2]

The regional geoelectric field peak amplitude used in GMD Vulnerability Assessment, E_{peak}, can be obtained from the reference geoelectric field value of 8 V/km for the benchmark GMD event (1) or 12 V/km for the supplemental GMD event (2) using the following relationships:

$$E_{peak} = 8 \times \alpha \times \beta\beta_{\,b} \text{ (V/km)} \quad (1)$$

$$E_{peak} = 12 \times \alpha \times \beta_{\,s} \text{ (V/km)} \quad (2)$$

where α is the scaling factor to account for local geomagnetic latitude, and β is a scaling factor to account for the local earth conductivity structure. Subscripts *b* and *s* for the β scaling factor denotes association with the benchmark or supplemental GMD events, respectively.

Scaling the Geomagnetic Field

The benchmark and supplemental GMD event isevents are defined for geomagnetic latitude of 60° and it must be scaled to account for regional differences based on geomagnetic latitude. Table 2 provides a scaling factor correlating peak geoelectric field to geomagnetic latitude. Alternatively, the scaling factor α is computed with the empirical expression

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (2)$$

[1] The benchmark GMD event description is available on the Project 2013-03 Geomagnetic Disturbance Mitigation projectRelated Information page:http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx for TPL-007-1:; http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

[2] The extent of local enhancements is on the order of 100 km in North-South (latitude) direction but longer in East-West (longitude) direction. The local enhancement in the geomagnetic field occurs over the time period of 2-5 minutes. Additional information is available in the sSupplemental GMD eEvent dDescription white paper on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

$$\alpha = 0.001 \cdot e^{(0.115 \cdot L)} \quad (3)$$

where L is the geomagnetic latitude in degrees and 0.1 ≤ α ≤ 1.

For large planning areas that cover more than one scaling factor from Table 2, the GMD Vulnerability Assessment should be based on a peak geoelectric field that is:

- calculated by using the most conservative (largest) value for α; or
- calculated assuming a non-uniform or piecewise uniform geomagnetic field.

Table 2– Geomagnetic Field Scaling Factors for the Benchmark and Supplemental GMD Events

Geomagnetic Latitude (Degrees)	Scaling Factor1 (α)
≤ 40	0.10
45	0.2
50	0.3
54	0.5
56	0.6
57	0.7
58	0.8
59	0.9
≥ 60	1.0

Scaling the Geoelectric Field

The benchmark GMD event is defined for the reference Quebec earth model described in Table 4. The peak geoelectric field, E_{peak}, used in a GMD Vulnerability Assessment may be obtained by either:

- Calculating the geoelectric field for the ground conductivity in the planning area and the reference geomagnetic field time series scaled according to geomagnetic latitude, using a procedure such as the plane wave method described in the NERC GMD Task Force GIC Application Guide;[3] or
- Using the earth conductivity scaling factor β from Table 3 that correlates to the ground conductivity map in Figure 1 or Figure 2. Along with the scaling factor α from equation (2 3) or Table 2, β is applied to the reference geoelectric field using equation (1 or 2, as applicable) to obtain the regional geoelectric field peak amplitude E_{peak} to be used in GMD Vulnerability Assessment Assessments. When a ground conductivity model is not

[3] Available at the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

available, the planning entity should use the largest β factor of adjacent physiographic regions or a technically justified value.

The earth models used to calculate Table 3 for the United States were obtained from publicly available information published on the U. S. Geological Survey website.[4] The models used to calculate Table 3 for Canada were obtained from Natural Resources Canada (NRCan) and reflect the average structure for large regions. A planner can also use specific earth model(s) with documented justification and the reference geomagnetic field time series to calculate the β factor(s) as follows:

$\beta_b = E/8$~~$\beta = E/8$~~ for the benchmark GMD event (4)

$\beta_s = E/12$ for the supplemental GMD event (5)

where *E* is the absolute value of peak geoelectric in V/km obtained from the technically justified earth model and the reference geomagnetic field time series.

For large planning areas that span more than one β scaling factor, the most conservative (largest) value for β may be used in determining the peak geoelectric field to obtain conservative results. Alternatively, a planner could perform analysis using a non-uniform or piecewise uniform geoelectric field.

Applying the Localized Peak Geoelectric Field in the Supplemental GMD Event

The peak geoelectric field of the supplemental GMD event occurs in a localized area.[5] Planners have flexibility to determine how to apply the localized peak geoelectric field over the planning area in performing GIC calculations. Examples of approaches are:

- Apply the peak geoelectric field (12 V/km scaled to the planning area) over the entire planning area;
- Apply a spatially limited (12 V/km scaled to the planning area) peak geoelectric field (e.g., 100 km in North-South latitude direction and 500 km in East-West longitude direction) over a portion(s) of the system, and apply the benchmark GMD event over the rest of the system; or
- Other methods to adjust the benchmark GMD event analysis to account for the localized geoelectric field enhancement of the supplemental GMD event.

[4] Available at http://geomag.usgs.gov/conductivity/

[5] See the Supplemental Geomagnetic Disturbance Description white paper located on the Project 2013-03 Geomagnetic Disturbance Mitigation project page: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

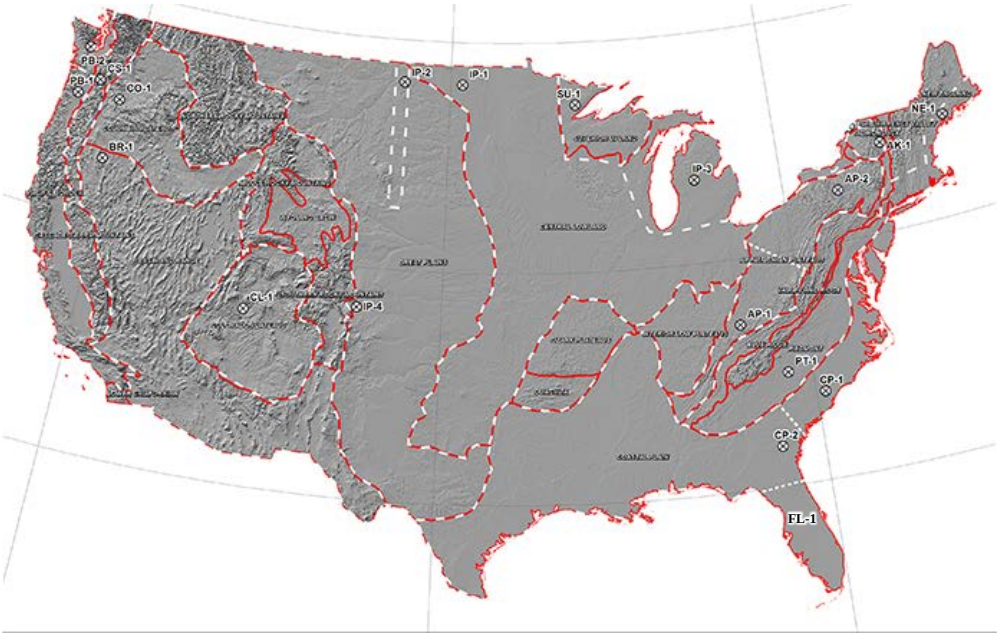


Figure 1: Physiographic Regions of the Continental United States[6]

Figure 2: Physiographic Regions of Canada

6 Additional map detail is available at the U.S. Geological Survey (http://geomag.usgs.gov/)

Table 3 – Geoelectric Field Scaling Factors		
~~USGS~~ Earth model	Scaling Factor ~~(β)~~Benchmark Event (β_b)	Scaling Factor Supplemental Event (β_s)
AK1A	0.56	0.51
AK1B	0.56	0.51
AP1	0.33	0.30
AP2	0.82	0.78
BR1	0.22	0.22
CL1	0.76	0.73
CO1	0.27	0.25
CP1	0.81	0.77
CP2	0.95	0.86
FL1	0.~~74~~76	0.73
CS1	0.41	0.37
IP1	0.94	0.90
IP2	0.28	0.25
IP3	0.93	0.90
IP4	0.41	0.35
NE1	0.81	0.77
PB1	0.62	0.55
PB2	0.46	0.39
PT1	1.17	1.19
SL1	0.53	0.49
SU1	0.93	0.90
BOU	0.28	0.24
FBK	0.56	0.56
PRU	0.21	0.22
BC	0.67	0.62
PRAIRIES	0.96	0.88
SHIELD	1.0	1.0
ATLANTIC	0.79	0.76

Rationale: Scaling factors in Table 3 are dependent upon the frequency content of the reference storm. Consequently, the benchmark GMD event and the supplemental GMD event may produce different scaling factors for a given earth model.

The scaling factor associated with the benchmark GMD event for the Florida earth model (FL-1) has been updated based on the earth model published on the USGS public website.

Table 4 – Reference Earth Model (Quebec)	
Layer Thickness (km)	Resistivity (Ω-m)
15	20,000
10	200
125	1,000
200	100
∞	3

Reference Geomagnetic Field Time Series or ~~Waveshape~~[7]Waveform for the Benchmark GMD Event[8]

The geomagnetic field measurement record of the March 13-14 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory is the basis for the reference geomagnetic field ~~waveshape~~waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 3) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 8 V/km (see Figures 4 and 5). The ~~Sampling~~ sampling rate for the geomagnetic field ~~waveshape~~waveform is 10 seconds.[9] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate benchmark conductivity scaling factor ~~β~~.β_b.

~~[7] Refer to the Benchmark GMD Event Description for details on the determination of the reference geomagnetic field waveshape: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

[8] Refer to the Benchmark GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

[9] The data file of the benchmark geomagnetic field ~~waveshape~~waveform is available on the ~~NERC GMD Task Force project~~Related Information page~~: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx~~ for TPL-007-1: http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

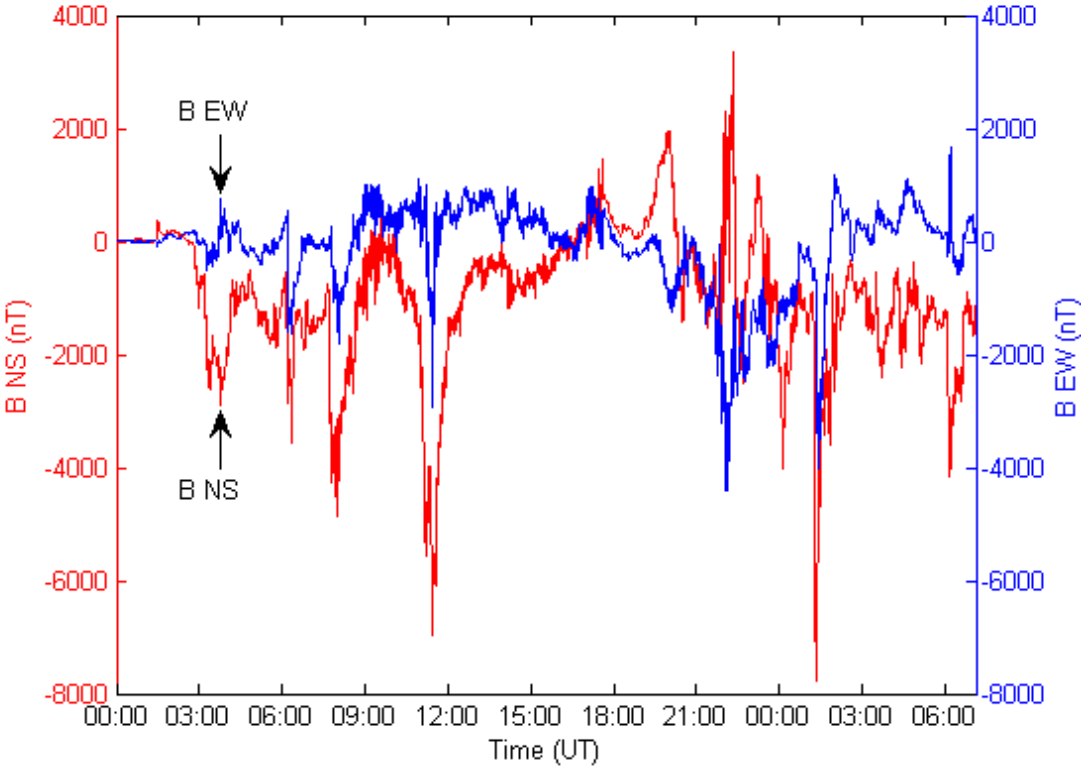


Figure 3: Benchmark Geomagnetic Field ~~Waveshape~~Waveform. Red B_n (Northward), Blue B_e (Eastward)

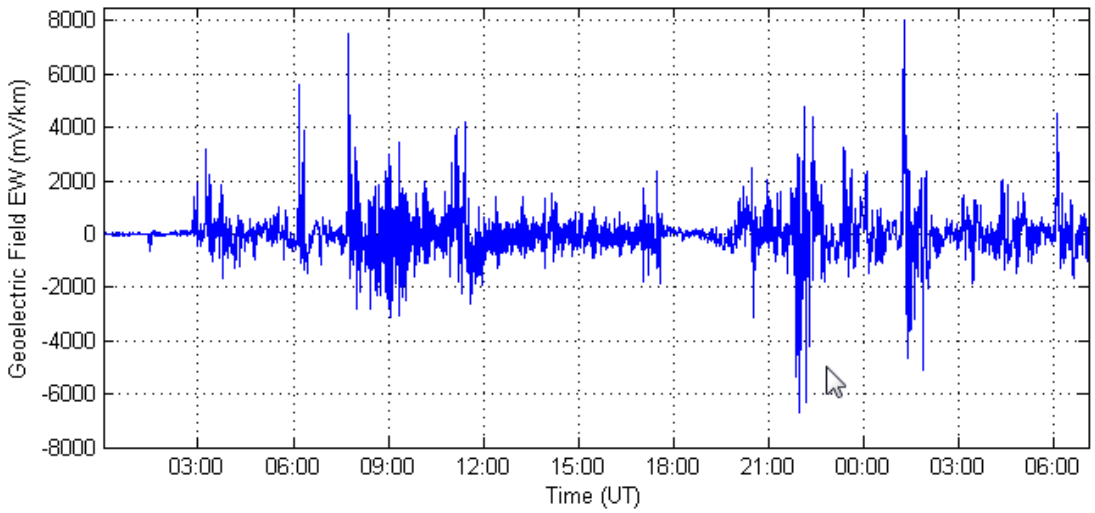


Figure 4: Benchmark Geoelectric Field ~~Waveshape~~Waveform - E_E (Eastward)

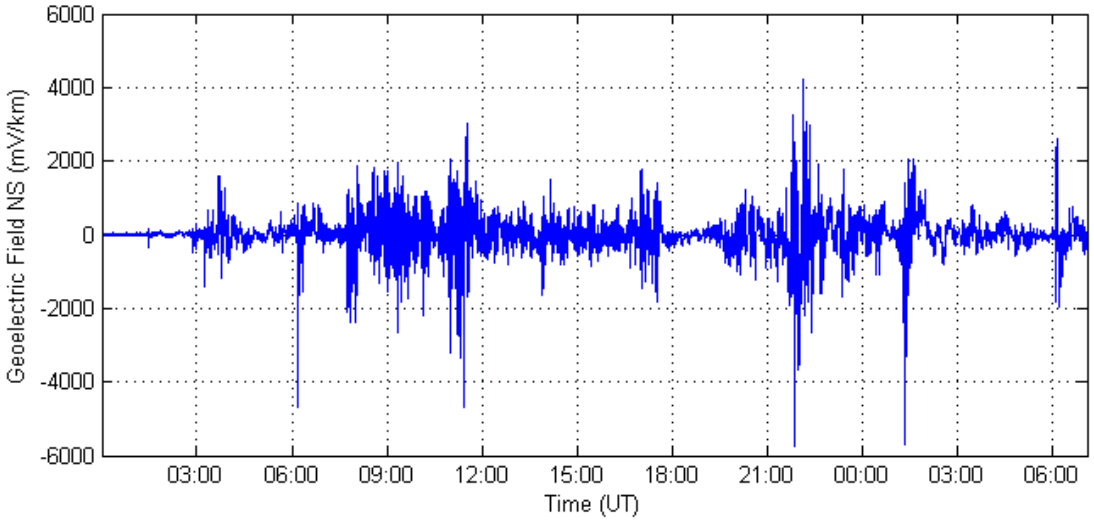


Figure 5: Benchmark Geoelectric Field ~~Waveshape~~Waveform – E_N (Northward)

Reference Geomagnetic Field Time Series or Waveform for the Supplemental GMD Event[10]

The geomagnetic field measurement record of the March 13-14, 1989 GMD event, measured at NRCan's Ottawa geomagnetic observatory is the basis for the reference geomagnetic field waveform to be used to calculate the GIC time series, GIC(t), required for transformer thermal impact assessment for the supplemental GMD event. The supplemental GMD event waveform differs from the benchmark GMD event waveform in that the supplemental GMD event waveform has a local enhancement.

The geomagnetic latitude of the Ottawa geomagnetic observatory is 55°; therefore, the amplitude of the geomagnetic field measurement data were scaled up to the 60° reference geomagnetic latitude (see Figure 6) such that the resulting peak geoelectric field amplitude computed using the reference earth model was 12 V/km (see Figure7). The sampling rate for the geomagnetic field waveform is 10 seconds.[11] To use this geoelectric field time series when a different earth model is applicable, it should be scaled with the appropriate supplemental conductivity scaling factor β_S.

[10] Refer to the Supplemental GMD Event Description white paper for details on the determination of the reference geomagnetic field waveform: http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

[11] The data file of the benchmark geomagnetic field waveform is available on the NERC GMD Task Force project page: http://www.nerc.com/comm/PC/Pages/Geomagnetic-Disturbance-Task-Force-(GMDTF)-2013.aspx

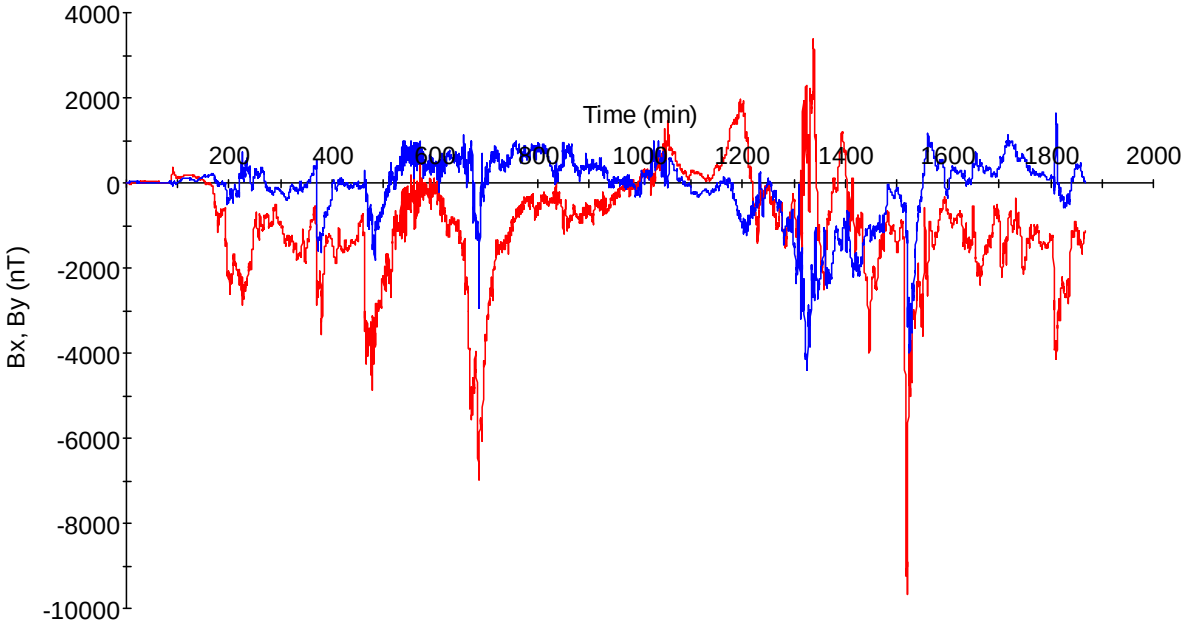


Figure 6: Supplemental Geomagnetic Field Waveform. Red B_n (Northward), Blue B_e (Eastward)

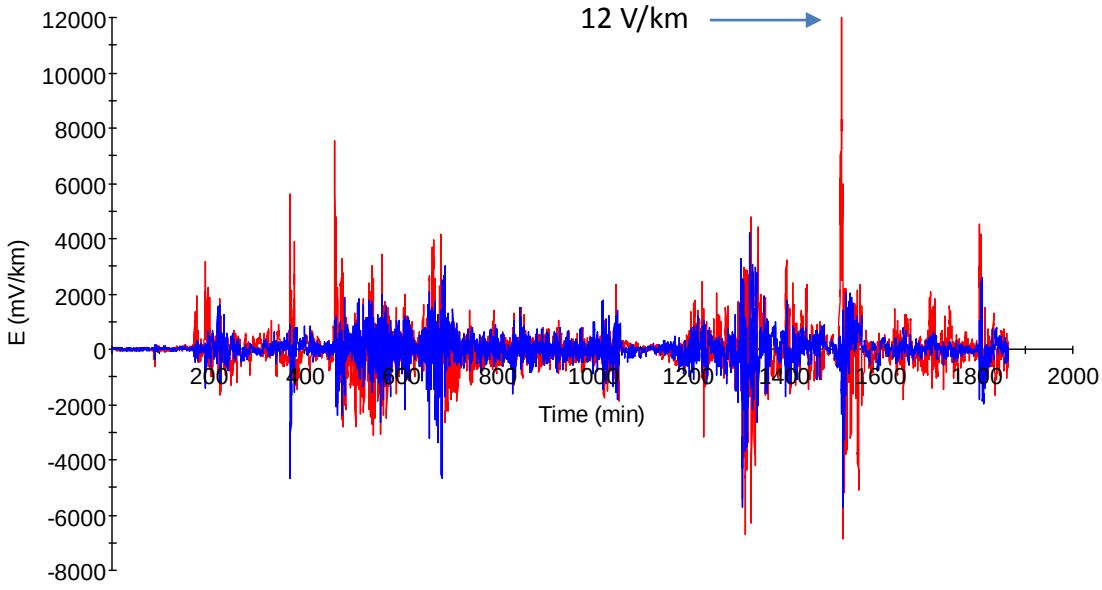


Figure 7: Supplemental Geoelectric Field Waveform. ~~Red~~ Blue E_n (Northward), ~~Blue~~ Red E_e (Eastward)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~As defined in the NERC Rules of Procedure,~~ "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with ~~the NERC~~mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention

The following evidence retention ~~periods~~period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the ~~CEA~~Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

~~The Planning Coordinator, Transmission Planner, Transmission Owner, and Generator Owner~~The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation~~:~~.

- For Requirements R1, R2, R3, R5, R6, R9, and ~~R6~~R10, each responsible entity shall retain documentation as evidence for five years.
- For ~~Requirement~~Requirements R4 and R8, each responsible entity shall retain documentation of the current GMD Vulnerability Assessment and the preceding GMD Vulnerability Assessment.
- For Requirement R7, each responsible entity shall retain documentation as evidence for five years or until all actions in the Corrective Action Plan are completed, whichever is later.
- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

~~If a Planning Coordinator, Transmission Planner, Transmission Owner, or Generator Owner is found non-compliant it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.~~

~~The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.~~

~~**1.3. Compliance Monitoring and Assessment Processes:**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigations~~

~~Self-Reporting~~

~~Complaints~~

~~**1.4. Additional Compliance Information**~~

~~None~~

- For Requirements R11 and R12, each responsible entity shall retain documentation as evidence for three years.

1.3. Compliance Monitoring and Assessment Processes: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Table of Compliance Elements

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Long-term Planning~~	~~Lower~~	N/A	N/A	N/A	The Planning Coordinator, in conjunction with its Transmission Planner(s), failed to determine and identify individual or joint responsibilities of the Planning Coordinator and Transmission Planner(s) in the Planning Coordinator's planning area for maintaining models ~~and~~, performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s).~~, and implementing process(es) to obtain

						GMD measurement data as specified in this standard.
R2	~~Long-term Planning~~	~~High~~	N/A	N/A	The responsible entity did not maintain either System models or GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.	The responsible entity did not maintain both System models and GIC System models of the responsible entity's planning area for performing the study or studies needed to complete benchmark and supplemental GMD Vulnerability Assessment~~(s)~~.
R3	~~Long-term Planning~~	~~Medium~~	N/A	N/A	N/A	The responsible entity did not have criteria for acceptable System steady state voltage performance for its System during the ~~benchmark~~ GMD ~~event~~events described in Attachment 1 as required.
R4	~~Long-term Planning~~	~~High~~	The responsible entity completed a benchmark GMD	The responsible entity's completed benchmark GMD	The responsible entity's completed benchmark GMD	The responsible entity's completed benchmark GMD

			Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy one of elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy two of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last benchmark GMD Vulnerability Assessment.	Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R4, Parts 4.1 through 4.3; OR The responsible entity completed a benchmark GMD Vulnerability Assessment, but it was more than 72 calendar months since the last benchmark GMD Vulnerability Assessment; OR The responsible entity does not have a completed benchmark GMD Vulnerability Assessment.
R5	~~Long-term Planning~~	~~Medium~~	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each

			equal to 100 calendar days after receipt of a written request.	than or equal to 110 calendar days after receipt of a written request.	receipt of a written request.	applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R6	~~Long-term Planning~~	~~Medium~~	The responsible entity failed to conduct a benchmark thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal impact assessment for	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal	The responsible entity failed to conduct a benchmark thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase; OR The responsible entity conducted a benchmark thermal

			its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.	impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R5, Part 5.1, is 75 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R5, Part 5.1; OR The responsible entity failed to include three of the required elements as listed in Requirement R6, Parts 6.1 through 6.3.
R7			The responsible entity's Corrective Action Plan failed to comply with one of the elements in	The responsible entity's Corrective Action Plan failed to comply with two of the elements in	The responsible entity's Corrective Action Plan failed to comply with three of the elements in	The responsible entity's Corrective Action Plan failed to comply with four or more of the elements

			Requirement R7, Parts 7.1 through 7.5.	Requirement R7, Parts 7.1 through 7.5.	Requirement R7, Parts 7.1 through 7.5.	in Requirement R7, Parts 7.1 through 7.5; OR The responsible entity did not have a Corrective Action Plan as required by Requirement R7.
R8			The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 60 calendar months and less than or equal to 64 calendar months since the last supplemental GMD Vulnerability Assessment; OR The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy one of elements listed in Requirement R8, Parts 8.1 through 8.4;	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy two of elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 64 calendar months and less than or equal to 68 calendar months since the last supplemental GMD	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy three of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 68 calendar months and less than or equal to 72 calendar months since the last supplemental GMD Vulnerability Assessment.	The responsible entity's completed supplemental GMD Vulnerability Assessment failed to satisfy four of the elements listed in Requirement R8, Parts 8.1 through 8.4; OR The responsible entity completed a supplemental GMD Vulnerability Assessment, but it was more than 72 calendar months since the last supplemental GMD Vulnerability Assessment; OR

				Vulnerability Assessment.		The responsible entity does not have a completed supplemental GMD Vulnerability Assessment.
R9			The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 90 calendar days and less than or equal to 100 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 100 calendar days and less than or equal to 110 calendar days after receipt of a written request.	The responsible entity provided the effective GIC time series, GIC(t), in response to written request, but did so more than 110 calendar days after receipt of a written request.	The responsible entity did not provide the maximum effective GIC value to the Transmission Owner and Generator Owner that owns each applicable BES power transformer in the planning area; OR The responsible entity did not provide the effective GIC time series, GIC(t), upon written request.
R10			The responsible entity failed to conduct a supplemental thermal impact assessment for 5% or less or one of its solely owned and jointly owned applicable BES power	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 5% up to (and including) 10% or two of its solely owned and jointly	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 10% up to (and including) 15% or three of its solely owned and jointly	The responsible entity failed to conduct a supplemental thermal impact assessment for more than 15% or more than three of its solely owned and jointly owned

			transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 24 calendar months and less than or equal to 26 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1.	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 26 calendar months and less than or equal to 28 calendar months of receiving GIC flow information specified	owned applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 28 calendar months and less than or equal to 30 calendar months of receiving GIC flow information specified	applicable BES power transformers (whichever is greater) where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase; OR The responsible entity conducted a supplemental thermal impact assessment for its solely owned and jointly owned applicable BES power transformers where the maximum effective GIC value provided in Requirement R9, Part 9.1, is 85 A or greater per phase but did so more than 30 calendar months of receiving GIC flow information specified in Requirement R9, Part 9.1; OR

				in Requirement R9, Part 9.1; OR The responsible entity failed to include one of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	in Requirement R9, Part 9.1; OR The responsible entity failed to include two of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.	The responsible entity failed to include three of the required elements as listed in Requirement R10, Parts 10.1 through 10.3.
R11			N/A	N/A	N/A	The responsible entity did not implement a process to obtain GIC monitor data from at least one GIC monitor located in the Planning Coordinator's planning area or other part of the system included in the Planning Coordinator's GIC System Model.
R12			N/A	N/A	N/A	The responsible entity did not implement a process to obtain geomagnetic field data for its Planning Coordinator's planning area.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

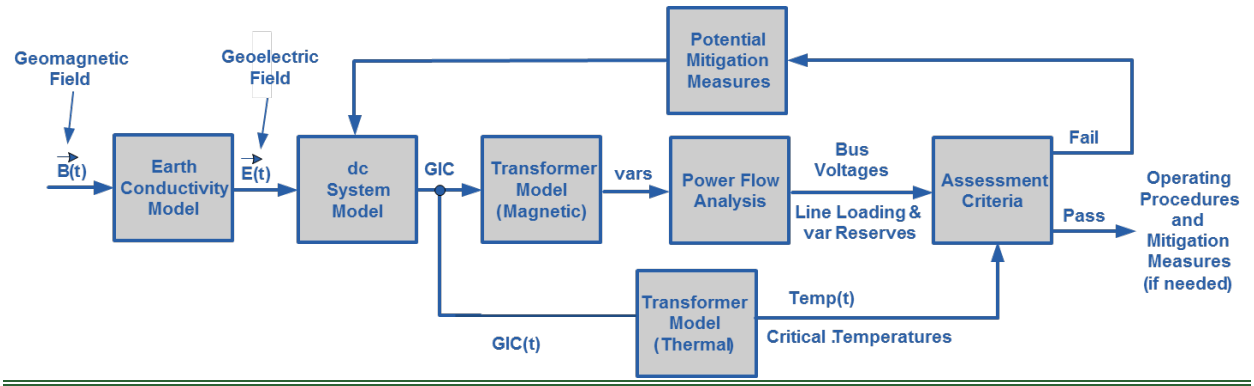
None.

Version History

Version	Date	Action	Change Tracking
1	December 17, 2014	Adopted by the NERC Board of Trustees	
2	TBD	Revised to respond to directives in FERC Order No. 830.	Revised

Guidelines and Technical Basis

The diagram below provides an overall view of the GMD Vulnerability Assessment process:



The requirements in this standard cover various aspects of the GMD Vulnerability Assessment process.

Benchmark GMD Event (Attachment 1)

The benchmark GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a benchmark GMD Vulnerability Assessment. A white paper that includes the event description, analysis, and example calculations is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page at:

~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~http://www.nerc.com/pa/stand/Pages/TPL0071RI.aspx

Supplemental GMD Event (Attachment 1)

The supplemental GMD event defines the geoelectric field values used to compute GIC flows that are needed to conduct a supplemental GMD Vulnerability Assessment. A white paper that includes the event description and analysis is available on the Project 2013-03 Geomagnetic Disturbance Mitigation project page:
http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Requirement R2

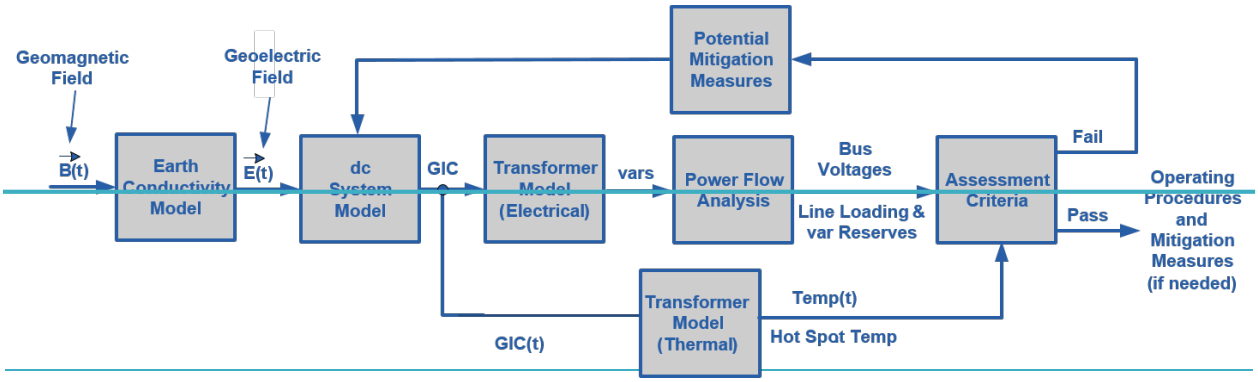
A GMD Vulnerability Assessment requires a GIC System model, which is a dc representation of the System, to calculate GIC flow. In a GMD Vulnerability Assessment, GIC simulations are used to determine transformer Reactive Power absorption and transformer thermal response. Details for developing the GIC System model are provided in the NERC GMD Task Force guide: *Application Guide for Computing Geomagnetically-Induced Current in the Bulk Power System*. The guide is available at:
http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

Underground pipe-type cables present a special modeling situation in that the steel pipe that encloses the power conductors significantly reduces the geoelectric field induced into the conductors themselves, while they remain a path for GIC. Solid dielectric cables that are not enclosed by a steel pipe will not experience a reduction in the induced geoelectric field. A planning entity should account for special modeling situations in the GIC system model, if applicable.

Requirement R4

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

~~The diagram below provides an overall view of the GMD Vulnerability Assessment process:~~



Requirement R5

The ~~transformer~~benchmark thermal impact assessment of transformers specified in Requirement R6 is based on GIC information for the ~~Benchmark~~benchmark GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R5 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for ~~transformer~~the benchmark thermal impact assessment. Only those transformers that experience an effective GIC value of 75 A or greater per phase require evaluation in Requirement R6.

GIC(t) provided in Part 5.2 is used to convert the steady ~~-~~state GIC flows to time-series GIC data for ~~transformer~~the benchmark thermal impact assessment~~.~~ of transformers. This information may be needed by one or more of the methods for performing a benchmark thermal impact assessment. Additional information is in the following section and the thermal impact assessment white paper.

The peak GIC value of 75 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R6

The benchmark thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper ~~posted on the project page.~~ The ERO enterprise has endorsed the white paper as Implementation Guidance for this requirement. The white paper is posted on the NERC compliance guidance page: ~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

http://www.nerc.com/pa/comp/guidance/Pages/default.aspx

Transformers are exempt from the benchmark thermal impact assessment requirement if the effective GIC value for the transformer is less than 75 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the *Screening Criterion for Transformer Thermal Impact Assessment* white paper posted on the Related Information page for ~~project~~TPL-007-1. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R6.

The benchmark threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R7

Technical considerations for GMD mitigation planning, including operating and equipment strategies, are available in Chapter 5 of the *GMD Planning Guide*. Additional information is available in the *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk-Power System*: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2012GMD.pdf

Requirement R8

The *GMD Planning Guide* developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The supplemental GMD Vulnerability Assessment process is similar to the benchmark GMD Vulnerability Assessment process described under Requirement R4.

Requirement R9

The supplemental thermal impact assessment specified of transformers in Requirement R10 is based on GIC information for the supplemental GMD Event. This GIC information is determined by the planning entity through simulation of the GIC System model and must be provided to the entity responsible for conducting the thermal impact assessment. GIC information should be provided in accordance with Requirement R9 each time the GMD Vulnerability Assessment is performed since, by definition, the GMD Vulnerability Assessment includes a documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 9.1 is used for the supplemental thermal impact assessment. Only those transformers that experience an effective GIC value of 85 A or greater per phase require evaluation in Requirement R10.

GIC(t) provided in Part 9.2 is used to convert the steady state GIC flows to time-series GIC data for the supplemental thermal impact assessment of transformers. This information may be needed by one or more of the methods for performing a supplemental thermal impact assessment. Additional information is in the following section.

The peak GIC value of 85 Amps per phase has been shown through thermal modeling to be a conservative threshold below which the risk of exceeding known temperature limits established by technical organizations is low.

Requirement R10

The supplemental thermal impact assessment of a power transformer may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. Approaches for conducting the assessment are presented in the *Transformer Thermal Impact Assessment* white paper discussed in the Requirement R6 section above. A revised version of the Transformer Thermal Impact Assessment white paper has been developed to include updated information pertinent to the supplemental GMD event and supplemental thermal impact assessment. This revised white paper is posted on the project page at:

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Transformers are exempt from the supplemental thermal impact assessment requirement if the effective GIC value for the transformer is less than 85 A per phase, as determined by a GIC analysis of the System. Justification for this criterion is provided in the revised *Screening*

Criterion for Transformer Thermal Impact Assessment white paper posted on the project page. A documented design specification exceeding this value is also a justifiable threshold criterion that exempts a transformer from Requirement R10.

The supplemental threshold criteria and its associated transformer thermal impact must be evaluated on the basis of effective GIC. Refer to the white papers for additional information.

Requirement R11

Technical considerations for GIC monitoring are contained in the NERC 2012 GMD Report (see Chapter 6). GIC monitoring is generally performed by Hall effect transducers that are attached to the neutral of the wye-grounded transformer. Data from GIC monitors is useful model validation and situational awareness.

Responsible entities consider the following in developing a process for obtaining GIC monitor data:

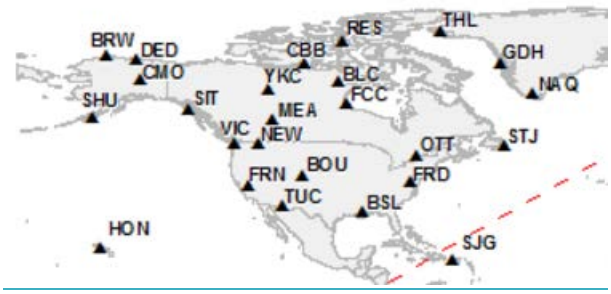
- **Monitor locations.** An entity's operating process may be constrained by location of existing GIC monitors. However, when planning for additional GIC monitoring installations consider that data from monitors located in areas found to have high GIC based on system studies may provide more useful information for validation and situational awareness purposes. Conversely, data from GIC monitors that are located in the vicinity of transportation systems using direct current (e.g., subways or light rail) may be unreliable.
- **Monitor specifications.** Capabilities of Hall effect transducers, existing and planned, should be considered in the operating process. When planning new GIC monitor installations, consider monitor data range (e.g., -500 A through + 500 A) and ambient temperature ratings consistent with temperatures in the region in which the monitor will be installed.
- **Sampling Interval.** An entity's operating process may be constrained by capabilities of existing GIC monitors. However, when possible specify data sampling during periods of interest at a rate of 10 seconds or faster.
- **Collection Periods.** The process should specify when the entity expects GIC data to be collected. For example, collection could be required during periods where the Kp index is above a threshold, or when GIC values are above a threshold. Determining when to discontinue collecting GIC data should also be specified to maintain consistency in data collection.
- **Data format.** Specify time and value formats. For example, Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow. Positive reference is flow from ground into transformer neutral. Time fields should indicate the sampled time rather than system or SCADA time if supported by the GIC monitor system.
- **Data retention.** The entity's process should specify data retention periods, for example 1 year. Data retention periods should be adequately long to support availability for the entity's model validation process and external reporting requirements, if any.

- **Additional information.** The entity's process should specify collection of other information necessary for making the data useful, for example monitor location and type of neutral connection (e.g., three-phase or single-phase).

Requirement R12

Magnetometers measure changes in the earth's magnetic field. Entities should obtain data from the nearest accessible magnetometer. Sources of magnetometer data include:

- Observatories such as those operated by U.S. Geological Survey and Natural Resources Canada, see figure below for locations (http://www.intermagnet.org/):



- Research institutions and academic universities;
- Entities with installed magnetometers.

Entities that choose to install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the Intermagnet Technical Reference Manual, which is available at:
http://www.intermagnet.org/publications/intermag_4-6.pdf

Rationale:

During development of ~~this standard~~TPL-007-1, text boxes were embedded within the standard to explain the rationale for various parts of the standard. ~~Upon BOT approval, the~~The text from the rationale text boxes was moved to this section~~.~~ upon approval of TPL-007-1 by the NERC Board of Trustees. In developing TPL-007-2, the SDT has made changes to the sections below only when necessary for clarity. Changes are marked with brackets [ ].

Rationale for Applicability:
Instrumentation transformers and station service transformers do not have significant impact on geomagnetically-induced current (GIC) flows; therefore, these transformers are not included in the applicability for this standard.

Terminal voltage describes line-to-line voltage.

Rationale for R1:
In some areas, planning entities may determine that the most effective approach to conduct a GMD Vulnerability Assessment is through a regional planning organization. No requirement in the standard is intended to prohibit a collaborative approach where roles and responsibilities are determined by a planning organization made up of one or more Planning Coordinator(s).

Rationale for R2:
A GMD Vulnerability Assessment requires a GIC System model to calculate GIC flow which is used to determine transformer Reactive Power absorption and transformer thermal response. Guidance for developing the GIC System model is provided in the GIC Application Guide developed by the NERC GMD Task Force and available at: http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GIC%20Application%20Guide%202013_approved.pdf

The System model specified in Requirement R2 is used in conducting steady state power flow analysis that accounts for the Reactive Power absorption of power transformer(s) due to GIC in the System.

The GIC System model includes all power transformer(s) with a high side, wye-grounded winding with terminal voltage greater than 200 kV. The model is used to calculate GIC flow in the network.

The projected System condition for GMD planning may include adjustments to the System that are executable in response to space weather information. These adjustments could include, for example, recalling or postponing maintenance outages.

The Violation Risk Factor (VRF) for Requirement R2 is changed from Medium to High. This change is for consistency with the VRF for approved standard TPL-001-4 Requirement R1, which is proposed for revision in the NERC filing dated August 29, 2014 (RM12-1-000). NERC guidelines require consistency among Reliability Standards.

Rationale for R3:
Requirement R3 allows a responsible entity the flexibility to determine the System steady state voltage criteria for System steady state performance in Table 1. Steady state voltage limits are an example of System steady state performance criteria.

Rationale for R4:
The GMD Vulnerability Assessment includes steady state power flow analysis and the supporting study or studies using the models specified in Requirement R2 that account for the effects of GIC. Performance criteria are specified in Table 1.

At least one System On-Peak Load and at least one System Off-Peak Load must be examined in the analysis.

Distribution of GMD Vulnerability Assessment results provides a means for sharing relevant information with other entities responsible for planning reliability. Results of GIC studies may affect neighboring systems and should be taken into account by planners.

The GMD Planning Guide developed by the NERC GMD Task Force provides technical information on GMD-specific considerations for planning studies. It is available at:

http://www.nerc.com/comm/PC/Geomagnetic%20Disturbance%20Task%20Force%20GMDTF%202013/GMD%20Planning%20Guide_approved.pdf

The provision of information in Requirement R4, Part 4.3, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R5:
This GIC information is necessary for determining the thermal impact of GIC on transformers in the planning area and must be provided to entities responsible for performing the thermal impact assessment so that they can accurately perform the assessment. GIC information should be provided in accordance with Requirement R5 as part of the GMD Vulnerability Assessment process since, by definition, the GMD Vulnerability Assessment includes documented evaluation of susceptibility to localized equipment damage due to GMD.

The maximum effective GIC value provided in Part 5.1 is used for transformer thermal impact assessment.

GIC(t) provided in Part 5.2 can alternatively be used to convert the steady -state GIC flows to time-series GIC data for transformer thermal impact assessment. This information may be needed by one or more of the methods for performing a thermal impact assessment. Additional guidance is available in the Transformer Thermal Impact Assessment white paper:

~~http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx~~

[http://www.nerc.com/pa/comp/guidance/Pages/default.aspx]

A Transmission Owner or Generator Owner that desires GIC(t) may request it from the planning entity. The planning entity shall provide GIC(t) upon request once GIC has been calculated, but no later than 90 calendar days after receipt of a request from the owner and after completion of Requirement R5, Part 5.1.

The provision of information in Requirement R5 shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R6:

The transformer thermal impact screening criterion has been revised from 15 A per phase to 75 A per phase~~.~~ [for the benchmark GMD event]. Only those transformers that experience an effective GIC value of 75 A per phase or greater require evaluation in Requirement R6. The justification is provided in the Thermal Screening Criterion white paper.

The thermal impact assessment may be based on manufacturer-provided GIC capability curves, thermal response simulation, thermal impact screening, or other technically justified means. The transformer thermal assessment will be repeated or reviewed using previous assessment results each time the planning entity performs a GMD Vulnerability Assessment and provides GIC information as specified in Requirement R5. Approaches for conducting the assessment are presented in the Transformer Thermal Impact Assessment white paper posted on the project page.

http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx

Thermal impact assessments are provided to the planning entity, as determined in Requirement R1, so that identified issues can be included in the GMD Vulnerability Assessment (R4), and the Corrective Action Plan (R7) as necessary.

Thermal impact assessments of non-BES transformers are not required because those transformers do not have a wide-area effect on the reliability of the interconnected Transmission system.

The provision of information in Requirement R6, Part 6.4, shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for R7:
Corrective Action Plans are defined in the NERC Glossary of Terms:

> *A list of actions and an associated timetable for implementation to remedy a specific problem.*

Corrective Action Plans must, subject to the vulnerabilities identified in the assessments, contain strategies for protecting against the potential impact of the ~~Benchmark~~[Bb]enchmark GMD event, based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Chapter 5 of the NERC GMD Task Force *GMD Planning Guide* provides a list of mitigating measures that may be appropriate to address an identified performance issue.

The provision of information in Requirement R7, Part 7.3~~,~~ [Part 7.5 in TPL-007-2], shall be subject to the legal and regulatory obligations for the disclosure of confidential and/or sensitive information.

Rationale for Table 3:
Table 3 has been revised to use the same ground model designation, FL1, as is being used by USGS. The calculated scaling factor for FL1 is 0.74~~.~~ [The scaling factor associated with the benchmark GMD event for the Florida earth model (FL-1) has been updated to 0.76 in TPL-007-2 based on the earth model published on the USGS public website.]

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the first draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	October 29, 2015
SAR posted for comment	May 26 – June 24, 2016
Informal Comment Period	April 25 – May 24, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 2017
45-day formal comment period with additional ballot	November 2017
10-day final ballot	February 2018
Board adoption	May 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title:** **Transmission System Planning Performance Requirements**

2. **Number:** **TPL-001-45**

3. **Purpose:** Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies.

4. **Applicability:**

   4.1. Functional Entity

   4.1.1. Planning Coordinator.

   4.1.2. Transmission Planner.

~~**5. Effective Date:** Requirements R1 and R7 as well as the definitions shall become effective on the first day of the first calendar quarter, 12 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, Requirements R1 and R7 become effective on the first day of the first calendar quarter, 12 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~Except as indicated below, Requirements R2 through R6 and Requirement R8 shall become effective on the first day of the first calendar quarter, 24 months after applicable regulatory approval. In those jurisdictions where regulatory approval is not required, all requirements, except as noted below, go into effect on the first day of the first calendar quarter, 24 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-4, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-4:~~

- ~~P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~
- ~~P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~
- ~~P2-1~~
- ~~P2-2 (above 300 kV)~~
- ~~P2-3 (above 300 kV)~~
- ~~P3-1 through P3-5~~

- ~~P4-1 through P4-5 (above 300 kV)~~
- ~~P5 (above 300 kV)~~

5. ~~Requirements~~Effective Date: See Implementation Plan.

B. Requirements and Measures

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the ~~MOD-010 and MOD-012 standards~~MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

1.1. System models shall represent:

1.1.1. Existing Facilities.

1.1.2. Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and 2.4.3.

1.1.3. New planned Facilities and changes to existing Facilities.

1.1.4. Real and reactive Load forecasts.

1.1.5. Known commitments for Firm Transmission Service and Interchange.

1.1.6. Resources (supply or demand side) required for Load.

M1. Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with ~~MOD-010 and MOD-012, MOD-032~~ MOD-032 including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or qualified past studies (as indicated in Requirement R2, Part 2.6), document assumptions, and document summarized results of the steady state analyses, short

circuit analyses, and Stability analyses. *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies need to include the following conditions:

2.1.1. System peak Load for either Year One or year two, and for year five.

2.1.2. System Off-Peak Load for one of the five years.

2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

2.1.4. For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response~~-~~:

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of known Transmission outages.

2.1.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be ~~studied~~assessed. The ~~studies~~analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, Part 2.6:

2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as qualified in Requirement R2, Part2.6. The following studies are required:

2.4.1. System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.2. System Off-Peak Load for one of the five years.

2.4.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

~~**2.4.3.**~~**2.4.4.** For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:

- Load level, Load forecast, or dynamic Load model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

~~**2.4.4.**~~**2.4.5.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible

unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

2.5. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed material generation additions or changes in that timeframe and be supported by current or past studies as qualified in Requirement R2, Part2.6 and shall include documentation to support the technical rationale for determining material changes.

2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

2.7. For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity case analyzed in accordance with Requirements R2, Parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. Examples of such actions include:

- Installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment.
- Installation, modification, or removal of Protection Systems or ~~Special Protection Systems~~ Remedial Action Scheme.

- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations.
- Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan.
- Use of rate applications, DSM, new technologies, or other initiatives.

2.7.2. Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.3. If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.4. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8. For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, Part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.1. List System deficiencies and the associated actions needed to achieve required System performance.

2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

M2. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has

prepared an annual Planning Assessment of its portion of the BES in accordance with Requirement R2.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

3.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, Part 3.4.

3.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, Part 3.5.

3.3. Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall:

3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

3.3.1.1. ~~3.3.1.1.~~ Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2. ~~3.3.1.2.~~ Tripping of Transmission elements where relay loadability limits are exceeded.

3.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

M3. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, Part 4.4.

4.1.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a ~~Special Protection System~~Remedial Action Scheme is not considered pulling out of synchronism.

4.1.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system elements other than the generating unit and its directly connected Facilities.

4.1.3. For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Planning Coordinator and Transmission Planner.

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

4.3. Contingency analyses for Requirement R4, Parts 4.1 and 4.2 shall-:

4.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:

4.3.1.1. ~~4.3.1.1.~~ Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2. ~~4.3.1.2.~~ Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3. ~~4.3.1.3.~~ Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

4.3.2. Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4. Those planning events in Table 1 that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list created of those Contingencies to be evaluated in Requirement R4, Part 4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1. Each Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R4, Part 4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

M4. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.

R5. Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M5. Each Transmission Planner and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

M6. Each Transmission Planner and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment. *[Violation Risk Factor: Low] [Time Horizon: Long-term Planning]*

M7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies that agreement has been reached on individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7.

R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

8.1. If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

~~B.~~C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit

The ~~**1.1 Compliance Enforcement Authority**~~

~~Regional Entity~~ applicable entity shall keep data identified in Measures M1 through M8 or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.

1.3. Compliance Monitoring and Enforcement Program As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

~~1.2~~ Compliance Monitoring Period and Reset Timeframe

1.4. :

Not applicable.

1.5. Compliance Monitoring and Enforcement Processes:

- Compliance Audits
- Self-Certifications
- Spot Checks
- Compliance Violation Investigations
- Self-Report
- Complaints

~~1.3~~ Additional Compliance Information

1.6. :

None~~-~~.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The responsible entity's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent two of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent three of the Requirement R1, Parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, Parts 1.1.1 through 1.1.6. OR The responsible entity's System model did not represent projected System conditions as described in Requirement R1. OR The responsible entity's System model did not use data consistent with that provided in accordance with the ~~MOD-010 and MOD-012~~ MOD-032 standards and other sources, including items represented in the Corrective Action Plan.
R2.	The responsible entity failed to comply with Requirement R2, Part 2.6.	The responsible entity failed to comply with Requirement R2, Part 2.3 or Part 2.8.	The responsible entity failed to comply with one of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, Part 2.5, or Part 2.7.	The responsible entity failed to comply with two or more of the following Parts of Requirement R2: Part 2.1, Part 2.2, Part 2.4, or Part 2.7. OR The responsible entity does not have a completed annual Planning Assessment.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The responsible entity did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for one of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R3, Part 3.2 to assess the impact of extreme events.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for two of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R3, Part 3.3.	The responsible entity did not perform studies as specified in Requirement R3, Part 3.1 to determine that the BES meets the performance requirements for three or more of the categories (P2 through P7) in Table 1. OR The responsible entity did not perform studies to determine that the BES meets the performance requirements for the P0 or P1 categories in Table 1. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R4.	The responsible entity did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR	The responsible entity did not perform studies as specified in Requirement R4, Part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		The responsible entity did not perform studies as specified in Requirement R4, Part 4.2 to assess the impact of extreme events.	The responsible entity did not perform Contingency analysis as described in Requirement R4, Part 4.3. ~~OR~~ ~~The responsible entity did not develop a Corrective Action Plan as described in Requirement R4, Part 4.6.~~	The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.
R5.	N/A	N/A	N/A	The responsible entity does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System.
R6.	N/A	N/A	N/A	The responsible entity failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6.
R7.	N/A	N/A	N/A	The Planning Coordinator, in conjunction with each of its Transmission Planners, failed to determine and identify individual or joint responsibilities for performing required studies.

~~C.~~D. Regional Variances

~~None.~~

E. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	February 8, 2005	BOT Approval	Revised
0	June 3, 2005	Fixed reference in M1 to read TPL-001-0 R2.1 and TPL-001-0 R2.2	Errata
0	July 24, 2007	Corrected reference in M1. to read TPL-001-0 R1 and TPL-001-0 R2.	Errata
0.1	October 29, 2008	BOT adopted errata changes; updated version number to “0.1”	Errata
0.1	May 13, 2009	FERC Approved – Updated Effective Date and Footer	Revised
1	Approved by Board of Trustees February 17, 2011	Revised footnote ‘b’ pursuant to FERC Order RM06-16-009	Revised (Project 2010-11)
2	August 4, 2011	Revision of TPL-001-1; includes merging and upgrading requirements of TPL-001-0, TPL-002-0, TPL-003-0, and TPL-004-0 into one, single, comprehensive, coordinated standard: TPL-001-2; and retirement of TPL-005-0 and TPL-006-0.	Project 2006-02 – complete revision
2	August 4, 2011	Adopted by Board of Trustees	
1	April 19, 2012	FERC issued Order 762 remanding TPL-001-1, TPL-002-1b, TPL-003-1a, and TPL-004-1. FERC also issued a NOPR proposing to remand TPL-001-2. NERC	

Version	Date	Action	Change Tracking
		has been directed to revise footnote 'b' in accordance with the directives of Order Nos. 762 and 693.	
3	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-3 was created after the Board of Trustees approved the revised footnote 'b' in TPL-002-2b, which was balloted and appended to: TPL-001-0.1, TPL-002-0b, TPL-003-0a, and TPL-004-0.	
4	February 7, 2013	Adopted by the NERC Board of Trustees. TPL-001-4 was adopted by the Board of Trustees as TPL-001-3, but a discrepancy in numbering was identified and corrected prior to filing with the regulatory agencies.	
4	October 17, 2013	FERC Order issued approving TPL-001-4 (Order effective December 23, 2013).	
4	May 7, 2014	NERC Board of Trustees adopted change to VRF in Requirement 1 from Medium to High.	Revision
4	November 26, 2014	FERC issued a letter order approving change to VRF in Requirement 1 from Medium to High.	
5	TBD	Adopted by the NERC Board of Trustees.	Revised To address reliability issues as identified in FERC Order No. 754 and Order No. 786 directives and update the references to the MOD Reliability Standards in TPL-001.

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. .The process must include the following:

1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues
2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:
    a. Date, time, and location for the meeting
    b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
    c. Provisions for a stakeholder comment period
3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants
4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns
5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:
    a. System Load level and estimated annual hours of exposure at or above that Load level
    b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency
2. Amount of Non-Consequential Load Loss with:
    a. The estimated number and type of customers affected

b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance

4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance

5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12

6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12

7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12

8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

1. The voltage level of the Contingency is greater than 300 kV

   a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or

   b. For a non-generator step-up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step-up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step-Up transformer)

The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:

a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.

b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.

c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

d. Simulate Normal Clearing unless otherwise specified.

e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Steady State Only:

f. Applicable Facility Ratings shall not be exceeded.

g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner.

h. Planning event P0 is applicable to steady state only.

i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Stability Only:

j. Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	N/A	EHV, HV	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single Pole of a DC line	SLG			
P2 Single Contingency	Normal System	1. Opening of a line section w/o a fault [7]	N/A	EHV, HV	No[9]	No[12]
		2. Bus Section Fault	SLG	EHV	No[9]	No
				HV	Yes	Yes
		3. Internal Breaker Fault [8] (non-Bus-tie Breaker)	SLG	EHV	No[9]	No
				HV	Yes	Yes
		4. Internal Breaker Fault (Bus-tie Breaker) [8]	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P3 Multiple Contingency	Loss of generator unit followed by System adjustments[9]	Loss of one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6]	3Ø	EHV, HV	No[9]	No[12]
		5. Single pole of a DC line	SLG			
P4 Multiple Contingency *(Fault plus stuck breaker[10])*	Normal System	Loss of multiple elements caused by a stuck breaker [10](non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
		6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P5 Multiple Contingency *(Fault plus ~~relay~~ non-redundant component of a Protection System failure to operate)*	Normal System	Delayed Fault Clearing due to the failure of a non-redundant ~~relay~~ component of a Protection System[13] protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuit 3. Transformer [5] 4. Shunt Device [6] 5. Bus Section	SLG	EHV	No[9]	No
				HV	Yes	Yes
P6 Multiple Contingency *(Two overlapping singles)*	Loss of one of the following followed by System adjustments.[9] 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device[6] 4. Single pole of a DC line	Loss of one of the following: 1. Transmission Circuit 2. Transformer [5] 3. Shunt Device [6]	3Ø	EHV, HV	Yes	Yes
		4. Single pole of a DC line	SLG	EHV, HV	Yes	Yes

Category	Initial Condition	Event [1]	Fault Type [2]	BES Level [3]	Interruption of Firm Transmission Service Allowed [4]	Non-Consequential Load Loss Allowed
P7 Multiple Contingency *(Common Structure)*	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure [11] 2. Loss of a bipolar DC line	SLG	EHV, HV	Yes	Yes

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability

For all extreme events evaluated:

a. Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency.

b. Simulate Normal Clearing unless otherwise specified.

Steady State

1. Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.
2. Local area events affecting the Transmission System such as:
   a. Loss of a tower line with three or more circuits.[11]
   b. Loss of all Transmission lines on a common Right-of-Way[11].
   c. Loss of a switching station or substation (loss of one voltage level plus transformers).
   d. Loss of all generating units at a generating station.
   e. Loss of a large Load or major Load center.
3. Wide area events affecting the Transmission System based on System topology such as:
   a. Loss of two generating stations resulting from conditions such as:
      i. Loss of a large gas pipeline into a region or multiple regions that have significant gas-fired generation.
      ii. Loss of the use of a large body of water as the cooling source for generation.

Stability

1. With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2. Local or wide area events affecting the Transmission System such as:
   a. 3Ø fault on generator with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   b. 3Ø fault on Transmission circuit with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   c. 3Ø fault on transformer with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   d. 3Ø fault on bus section with stuck breaker[10] ~~or a relay failure[13]~~ resulting in Delayed Fault Clearing.
   e. 3Ø fault on generator with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.
   f. 3Ø fault on Transmission circuit with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing.

iii. Wildfires. iv. Severe weather, e.g., hurricanes, tornadoes, etc. v. A successful cyber attack. vi. Shutdown of a nuclear power plant(s) and related facilities for a day or more for common causes such as problems with similarly designed plants. b. Other events based upon operating experience that may result in wide area disturbances.	g. 3Ø fault on transformer with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. h. 3Ø fault on bus section with failure of a non-redundant component of a Protection System[13] resulting in Delayed Fault Clearing. ~~d.~~i. 3Ø internal breaker fault. ~~e.~~j. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances

Table 1 – Steady State & Stability Performance Footnotes (Planning Events and Extreme Events)
1. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed event determines the stated performance criteria regarding allowances for interruptions of Firm Transmission Service and Non-Consequential Load Loss.
2. Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
3. Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss.
4. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.
5. For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the BES connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
6. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
7. Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
8. An internal breaker fault means a breaker failing internally, thus creating a System fault which must be cleared by protection on both sides of the breaker.
9. An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered.

Table 1 – Steady State & Stability Performance Footnotes
(Planning Events and Extreme Events)

10. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
11. Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
12. An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following planning events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized under footnote 12 within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss for a non-US Registered Entity should be implemented in a manner that is consistent with, or under the direction of, the applicable governmental authority or its agency in the non-US jurisdiction.
13. For purposes of this standard, non-redundant components of a Protection System to consider are as follows:
    1. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;
    2. A single communications system, necessary for correct operation of a communication-aid protection scheme required for Normal Clearing, which is not monitored or not reported;
    3. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;
    4. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.~~Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).~~

Attachment 1

I. Stakeholder Process

During each Planning Assessment before the use of Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in the Near-Term Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of footnote 12 is reviewed through an open and transparent stakeholder process. The responsible entity can utilize an existing process or develop a new process. The process must include the following:

~~6.~~1. Meetings must be open to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues

~~7.~~2. Notice must be provided in advance of meetings to affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda with:

   a. Date, time, and location for the meeting
   b. Specific location(s) of the planned Non-Consequential Load Loss under footnote 12
   c. Provisions for a stakeholder comment period

~~8.~~3. Information regarding the intended purpose and scope of the proposed Non-Consequential Load Loss under footnote 12 (as shown in Section II below) must be made available to meeting participants

~~9.~~4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns

~~10.~~5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction

An entity does not have to repeat the stakeholder process for a specific application of footnote 12 utilization with respect to subsequent Planning Assessments unless conditions spelled out in Section II below have materially changed for that specific application.

II. Information for Inclusion in Item #3 of the Stakeholder Process

The responsible entity shall document the planned use of Non-Consequential Load Loss under footnote 12 which must include the following:

~~9.~~1. Conditions under which Non-Consequential Load Loss under footnote 12 would be necessary:

   a. System Load level and estimated annual hours of exposure at or above that Load level
   b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency

~~10.~~2. Amount of Non-Consequential Load Loss with:

   a. The estimated number and type of customers affected

b. An explanation of the effect of the use of Non-Consequential Load Loss under footnote 12 on the health, safety, and welfare of the community

~~11.~~3. Estimated frequency of Non-Consequential Load Loss under footnote 12 based on historical performance

~~12.~~4. Expected duration of Non-Consequential Load Loss under footnote 12 based on historical performance

~~13.~~5. Future plans to alleviate the need for Non-Consequential Load Loss under footnote 12

~~14.~~6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 12

~~15.~~7. Alternatives to Non-Consequential Load Loss considered and the rationale for not selecting those alternatives under footnote 12

~~16.~~8. Assessment of potential overlapping uses of footnote 12 including overlaps with adjacent Transmission Planners and Planning Coordinators

III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required

Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must ensure that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12 if either:

~~2.~~1. The voltage level of the Contingency is greater than 300 kV

a. If the Contingency analyzed involves BES Elements at multiple System voltage levels, the lowest System voltage level of the element(s) removed for the analyzed Contingency determines the stated performance criteria regarding allowances for Non-Consequential Load Loss under footnote 12, or

b. For a non-generator step up transformer outage Contingency, the 300 kV limit applies to the low-side winding (excluding tertiary windings). For a generator or generator step up transformer outage Contingency, the 300 kV limit applies to the BES connected voltage (high-side of the Generator Step Up transformer)

~~3.~~2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW

Once assurance has been received that the applicable regulatory authorities or governing bodies responsible for retail electric service issues do not object to the use of Non-Consequential Load Loss under footnote 12, the Planning Coordinator or Transmission Planner must submit the information outlined in items II.1 through II.8 above to the ERO for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Project 2015-10 Single Points of Failure TPL-001

Cost Effectiveness

Known Outages FERC Order No. 786

FERC Order No. 786 Paragraph 40 directs a change to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. See paragraphs 33-45 for the discussion on planned maintenance outages.

Overview of Commission Determination (Paragraphs 40-45)

The commission stated in Order No. 786 Paragraph 41:

- For the reasons discussed below, the Commission finds that planned maintenance outages of less than six months in duration may result in relevant impacts during one or both of the seasonal off-peak periods.
- Prudent transmission planning should consider maintenance outages at those load levels when planned outages are performed to allow for a single element to be taken out of service for maintenance without compromising the ability of the system to meet demand without loss of load.
- We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability.
- A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.

The Commission Disagreed with the following:

- Order No. 786 Paragraph 44: The existing TPL-001-4 for Category P3 covers generator maintenance outages, Category P6 covers transmission maintenance outages.
- Order No. 786 Paragraph 45: Planned outages of less than one year in duration should be addressed operationally by determining new operating limits and taking other actions to mitigate the planned outage.
- Order No. 786 Paragraph 45: Planned outages of less than six months is unnecessary since…10 year time frame.

Options Considered By Standard Drafting Team to Satisfy FERC Order

The following options considered by the NERC Standard Drafting Team for Requirement R1 Part 1.1.2 include (refer to SAMS recommendations):

Option 1 (SAMS recommendation from Order No. 754 Report):

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~ as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and R. 2.4.3.

Option 2

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~

Option 3

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least ~~six months~~ three months.

Option 4

Requirement R1, Part 1.1.2 Known outages(s) of generation or Transmission Facility(ies) with duration of at least ~~six~~ four months and any other significant planned outages of generation or Transmission Facility(ies) with a duration of less than four months that are expected to produce more severe System impacts on its portion of the BES. These outage coordinations are required to be performed for the season/load-levels that outages are normally planned at and shall be performed only in the Near-Term Transmission Planning Horizon.

Standard Drafting Team Proposal for Requirement R1 Part 1.1.2

The following is the option (Option 1) selected by the standard drafting team which satisfies the FERC Order. The following 1 option selected and in general aligns with the SAMS recommendation.

Option 1 (SAMS recommendation from Order No. 754 Report):

Requirement R1, Part 1.1.2 Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at least six months.~~ as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, parts 2.1.3 and R. 2.4.3.

Spare Equipment Strategy FERC Order No. 786

FERC Order No. 786 Paragraph 89 the Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. See Paragraph 85 through 89 of Order No. 786 for a discussion on spare equipment strategy.

Overview of Commission Determination (Order No. 786 Paragraphs 88-89)

The commission stated in Order No. 786:

- Order No. 786 Paragraph 88: The commission agrees that NERC has met the spare equipment strategy directive for steady state analysis under TPL-001-4 R2, Part 2.1.5.
- Order No. 786 Paragraph 88: The Commission finds that a spare equipment strategy for stability analysis is not addressed under category P6.
- Order No. 786 Paragraph 89: The commission is not persuaded by the explanation of NERC and others that a similar spare equipment strategy for stability analysis would cause unjustified burden because stability analysis is already required under category P6.

Options Considered By Standard Drafting Team to Satisfy FERC Order No. 786

Since the FERC Order in Paragraph 89 was very specific, there was only one option considered by the standard drafting team that met the requirements of the FERC Order Paragraph 89 request.

Option 1 Addition of Part 2.4.5

Requirement R1, Part 1.1.2 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be ~~studied~~ assessed. ~~The studies~~ Based upon this assessment, an analysis shall be performed for the selected P1 and P2 ~~categories~~ category events identified in Table 1 for which the unavailability ~~with the conditions that the System~~ is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.

Single Point of Failure of the Protection System

Based on Order No. 754 directive of September 15, 2011; NERC informational filing dated March 15, 2012; Section 1600 data request; and the 2nd NERC informational filing dated October 30, 2015, the SPCS/SAMS report to address the concern of Single Point Of Failure of a protection system:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

- Replace footnote 13 in TPL-001-4 with, "The components from the definition of "Protection System" for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single – station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices."
- Modify TPL-001-4 (Part 4.5) so that extreme event assessments must include evaluation of the three phase faults the described component failures of a Protection System that produce the more severe system impacts. For example, add a new second sentence that reads "[t]he list shall consider each of the extreme events in Table 1 – Steady State & Stability Performance Extreme Events; Stability column item number 2."

Options Considered By Standard Drafting Team to Satisfy FERC Order

Since some of the recommendations from the SPCS and SAMS report were so specific, there were no other options considered for the following:

- For Table 1 – Steady State & Stability Performance Planning Events, Category P5:
  - Replace "relay" with "component of a Protection System," and
  - Add superscript "13" to reference footnote 13 for the replaced term under the "Category" column.
- For Table 1 – Steady State & Stability Performance Extreme Events, under the Stability column, No. 2:
  - Remove the phrase "or a relay failure" from items a, b, c, and d to create distinct events only for stuck breakers.
  - Append four new events for the same items a, b, c, and d in the above bulleted item to create distinct events replacing "a relay failure" with "a component failure of a Protection System."

Different options were considered for footnote 13 language. These options are:

Option 1 Footnote 13

The Standard Drafting Team for TPL-001 considered revising footnote 13 to include all five components. In the NERC glossary of terms, a Protection System include five components. These are:

Protection System –

- Protective relays which respond to electrical quantities,
- Communications systems necessary for correct operation of protective functions
- Voltage and current sensing devices providing inputs to protective relays,

- Station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery-based dc supply), and
- Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Option 2 Footnote 13

The second option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[1]:

13. For the purposes of P5 of this standard, components of a Protection System include the following:

    a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

    b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;

    c. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

    ~~a.~~d. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.

Option 3 Footnote 13

a. The components from the definition of Protection System" for the purposes of this standard include:

b. protective relays that respond to electrical quantities,

c. single – station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and

d. control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Standard Drafting Team Proposal for Table 1 Footnote 13:

The Standard Drafting Team selected Option 2 which expands Protection System components to be considered to determine the impact to the BES if that component failed when a fault occurs.

[1] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

Option 2 Footnote 13

The second option was to have footnote 13 list four of the five components of a protection system but limit *"communications systems"* to only those that are not monitored or alarmed. The following is language for Footnote 13[2]:

For the purposes of P5 of this standard, components of a Protection System include the following:

a. A single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g. sudden pressure relaying;

b. A single communications system, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;

c. A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;

~~a.~~d. A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.

Addition of Corrective Action Plan for Extreme Event Three – Phase Faults:

The SPCS and SAMS report for Order No. 754 recommended that three phase faults involving single points of failure of a protection system be addressed. Additionally, the standard drafting team recognized that the Order No. 754 data requirement collected data for a three-phase fault and not a single-line-ground fault. The Order No. 754 data collection and report indicated a risk to the BES for three phase faults involving single points of failure of a protection system.

Options Considered By Standard Drafting Team to Satisfy FERC Order

Option 1:

Do not add anything for extreme event three-phase faults with protection failure.

Option 2:

Addition of Requirement 4 Part 4.2.1 and 4.2.2 as follows:

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

[2] Failure of voltage and current sensing device would result in a breaker operation without a fault which was considered not a reliability risk to the BES.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation~~List System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading~~.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

Standard Drafting Team Proposal

The standard drafting team selected Option 2 which was to add a requirement to require a Corrective Action Plan if a three-phase fault followed by a protection failure causes cascading.

Option 2:

4.2. Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, Part 4.5.

4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall:

4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation~~List System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading~~.

4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

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Mapping Document

Project 2015-10 Single Points of Failure TPL-001

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **1.1** System models shall represent: **1.1.1.** Existing Facilities **1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.	TPL-001-5, Requirement R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the ~~MOD-010 and MOD-012~~MOD-032 standard, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1. **1.1** System models shall represent: **1.1.1.** Existing Facilities **1.1.2.** Known outage(s) of generation or Transmission Facility(ies) ~~with a duration of at~~	<u>Requirement R1 body</u>. Updated referenced standard number in body of requirement. <u>Requirement R1 Part 1.1.2</u> Consistent with FERC Order 786 Para 40, the six-month threshold that could exclude planned maintenance outages is eliminated. Consultation with the Reliability Coordinator given that the Planning Coordinator and Transmission Planner maintain System models that represent known outages is consistent with IRO-017-1 Requirement R1, as well as IRO-017-1 Requirement R4 which requires the Planning Coordinator and Transmission Planner to jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
1.1.3. New planned Facilities and changes to existing Facilities **1.1.4.** Real and reactive Load forecasts **1.1.5.** Known commitments for Firm Transmission Service and Interchange **1.1.6.** Resources (supply or demand side) required for Load	~~least six months~~ as selected in consultation with the Reliability Coordinator for the Near-Term Planning Horizon for analyses pursuant to Requirement R2, Parts 2.1.3 and ~~R.~~ 2.4.3. **1.1.3.** New planned Facilities and changes to existing Facilities **1.1.4.** Real and reactive Load forecasts **1.1.5.** Known commitments for Firm Transmission Service and Interchange **1.1.6.** Resources (supply or demand side) required for Load	outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.
TPL-001-4, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	TPL-001-5, Requirement R2 Parts 2.1, 2.1.1, 2.1.2, 2.1.4 and 2.1.5 Parts 2..2, 2.2.1 Part 2.3 Parts 2.4, 2.4.1, 2.4.2 Part 2.5 Parts 2.6, 2.6.1, 2.6.2 Parts 2.7, 2.7.1, 2.7.2, 2.7.3, 2.7.4 Parts 2.8, 2.8.1, 2.8.2	No modifications made.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
TPL-001-4, Requirement R2 Part 2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.	TPL-001-5, Requirement R2 Part 2.1.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.	No modifications made.
TPL-001-4, Requirement R2 Part 2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: • Load level, Load forecast, or dynamic Load model assumptions. • Expected transfers.	TPL-001-4, Requirement R2 Part2.4.~~43~~. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: • Load level, Load forecast, or dynamic Load model assumptions. • Expected transfers.	TPL-001-5, Requirement R2, Part 2.4.4 TPL-001-4, Part 2.4.3 moved to TPL-001-5, Part 2.4.4

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
• Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	• Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios.	
	TPL-001-5, Requirement R2 Part 2.4.3. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.	TPL-001-5, Requirement R2, Part 2.4.3 Modified the standard to add a Stability analysis requirement for P1 events in Table 1, with known outages under appropriate System conditions, that includes similar language to that used for the steady state analysis stated in Requirement R2, Part 2.1.3.
	TPL-001-5, Requirement R2 Part 2.4.5. When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be	TPL-001-5, Requirement R2, Part 2.4.5 Consistent with FERC Order 786 Para 89, modified the standard to add Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis stated in Requirement R2, Part 2.1.5 to address stability analysis for spare equipment strategy.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	performed for the selected P1 and P2 category events identified in Table 1 for which the unavailability is expected to produce more severe System impacts on its portion of the BES. The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.	
TPL-001-4, Requirement R3	TPL-001-5, Requirement R3	No modifications made.
TPL-001-4, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	TPL-001-5, Requirement R4 Parts 4.1, 4.1.1, 4.1.2, 4.1.3 Parts 4.3, 4.3.1, 4.3.1.1, 4.3.1.2, 4.3.1.3, 4.3.2 Parts 4.4, 4.4.1 Part 4.5	No modifications made.
TPL-001-4, Requirement R4 4.2. Studies shall be performed to assess the impact of the extreme events which are	TPL-001-5, Requirement R4, 4.2. Studies shall be performed to assess the impact of the extreme events which are	<u>TPL-001-5, Requirement R4, Part 4.2</u> Modified the standard to differentiate between extreme events 2e-2h in the stability column of Table 1 from all other

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
identified by the list created in Requirement R4, Part 4.5.	identified by the list created in Requirement R4, Part 4.5. 4.2.1. If the analysis concludes there is Cascading caused by the occurrence of extreme events, excluding extreme events 2e-2h in the stability column, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted. 4.2.2. If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, an evaluation of possible actions designed to prevent the System from Cascading shall: 4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation. ~~List System deficiencies, the associated actions, and an associated timetable for implementation needed to prevent the System from Cascading.~~	extreme events with respect to additional documentation required when analysis concludes Cascading occurs. While the extreme events 2e-2h in the stability column of Table 1 remain as extreme events within TPL-001-5, the additional documentation specified in Requirement R4, Part 4.2.2.1 is indicated due to the reliability risk given a three phase fault and extended Delayed Clearing that may arise from the occurrence of these events. Likewise, when analysis concludes there is Cascading, Requirement R4, Part 4.2.2.2 specifies that these events be reviewed in subsequent annual Planning Assessments.

Standard: TPL-001-5		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Description and Change Justification**
	4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.	
TPL-001-4, Requirement R5	TPL-001-5, Requirement R5	No modifications made.
TPL-001-4, Requirement R6	TPL-001-5, Requirement R6	No modifications made.
TPL-001-4, Requirement R7	TPL-001-5, Requirement R7	No modifications made.
TPL-001-4, Requirement R8	TPL-001-5, Requirement R8	No modifications made.

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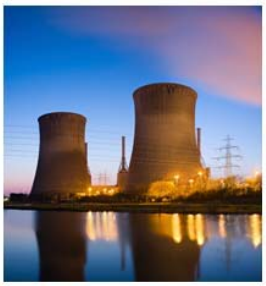
Project 2015-10

Single Points of Failure TPL-001 Technical Rationale

September 2017

RELIABILITY | ACCOUNTABILITY



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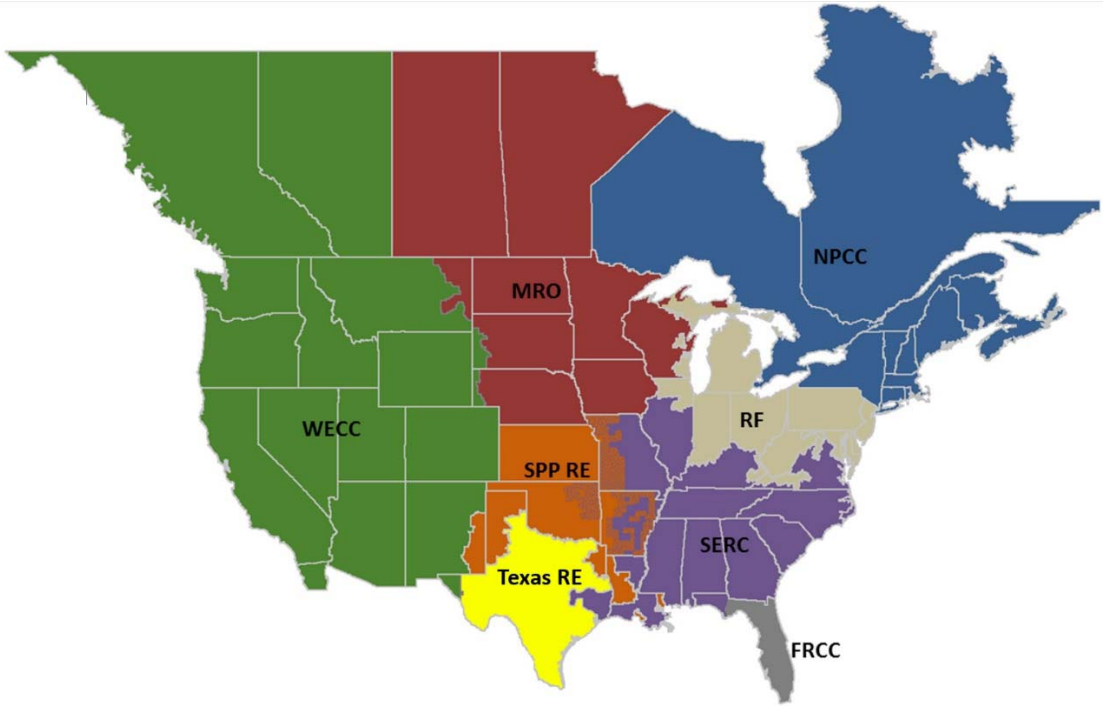
Preface

The North American Electric Reliability Corporation (NERC) is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the Electric Reliability Organization (ERO) for North America, subject to oversight by the Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

The North American BPS is divided into eight Regional Entity (RE) boundaries as shown in the map and corresponding table below.



The North American BPS is divided into eight RE boundaries. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.

FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
SPP RE	Southwest Power Pool Regional Entity
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

Project 2015-10 Technical Rationale provides the background and rationale for proposed revisions to Reliability Standard TPL-001-4. The proposed revisions address reliability issues concerning the study of single points of failure (SPF) on Protection Systems from FERC Order No. 754, directives from FERC Order No. 786 regarding planned maintenance outages and spare equipment strategy for stability analysis, and replaces references to the MOD-010 and MOD-012 standards with the MOD-032 Reliability Standard.

Key Concepts of FERC Order No. 754

The Standards Development Team (SDT) took into account the recommendations for modifying NERC Reliability Standard TPL-001-4 identified in the SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*. Proposed revisions changes extreme event (3-phase fault) to include a fault and failure of a non-redundant component of a Protection System. In "Table 1 – Steady State and Stability Performance Extreme Events," breaker failure and failure of a non-redundant component of a Protection System are differentiated. The SDT recognizes that sequence of Protection System action leading to Delayed Clearing may be quite different between the two causalities. Footnote 13 expands Protection System components to be considered for Category P5 and for extreme events 2e through 2h.

Key Concepts of FERC Order No. 786

The SDT considered the Commission's concern that the outages of significant facilities less than six months could be overlooked for planning purposes, Category P3 and P6 do not sufficiently cover planned maintenance outages, and Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two, and year five, and known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon. Proposed revisions remove the six month outage duration and replace it with consultation with the Reliability Coordinator (RC) to identify known outages of significant facilities that cannot be readily managed through near-term operational coordination processes. Proposed revisions includes stability study for long lead equipment that does not have a spare.

Summary of proposed revisions:

- Requirement R1 – Updated for MOD-032-1 standard.
- Requirement R1, Part 1.1.2 – Modified how known outages are selected for study.
- Requirement R2, Part 2.1.3 – Modified the P1 contingency events simulated (steady state) for known outages.
- Requirement R2, Part 2.4.3 – Added model conditions for stability analysis of P1 events for known outages.
- Requirement R2, Part 2.4.5 – Added stability analysis requirement for long lead time equipment unavailability.
- Requirement R4, Part 4.2 – Added documentation requirement if Cascading observed given 3-phase fault SPF.
- Table 1 – Modified Category P5 event to include SPF.
- Table 1 – Modified Extreme Events, Stability column to differentiate SPF from stuck breaker.
- Table 1 – Modified Footnote 13 to specify SPF.

Introduction

NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) is being modified to address reliability issues and standard modification directives contained in FERC Order No. 754[1] and FERC Order No. 786.[2] Proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address the reliability risks posed by SPF on Protection Systems.

Background

FERC Order No. 754

FERC Order No. 754 directed NERC to study the reliability risk associated with single points of failure (SPF) in Protection Systems. The NERC System Protection and Control Subcommittee (SPCS) and the System Analysis and Modelling Subcommittee (SAMS) conducted an assessment of Protection System SPF in response to FERC Order 754, including analysis of data collected pursuant to a request for data or information under Section 1600 of the NERC Rules of Procedure. The SPCS and SAMS report titled *Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request* provides extensive general discussion about the reliability risks associated with a SPF. Available

FERC Order No. 786

In Order No. 786, FERC directed NERC to address two issues. The first issue is the concern that the six month outage duration threshold could exclude planned maintenance outages of significant facilities from future planning assessments. FERC directed NERC to modify TPL-001-4 to address this concern. The second issue involves adding clarity regarding dynamic assessment of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy. FERC directed NERC to consider this issue upon its next review of TPL-001-4. The NERC SAMS developed a white paper documenting the technical analysis conducted by SAMS to address the two directives contained in the FERC Order 786. The white paper provides extensive general discussion regarding the directives.

[1] Order No. 754, *Interpretation of Transmission Planning Reliability Standard*, 136 FERC ¶ 61,186 (2011) ("Order No. 754").

[2] Order No. 786, *Transmission Planning Reliability Standards*, 145 FERC ¶ 61,051 (2013) ("Order No. 786").

Section 1: Single Points of Failure on Protection Systems (FERC Order No. 754)

NERC Advisory

On March 30, 2009, NERC issued an advisory[3] report notifying the industry that a SPF issue had caused three significant system disturbances in 5 years.

Transmission Owners, Generation Owners, and Distribution Providers owning Protection Systems installed on the Bulk Electric System were advised to address SPF on their Protection Systems when identified in routine system evaluations to prevent N-1 transmission system contingencies from evolving into more severe or even extreme events.

These entities were additionally advised to begin preparing an estimate of the resource commitment required to review, re-engineer, and develop a workable outage and construction schedule to address SPF on their Protection Systems.

FERC Order No. 754

In Order No. 754 Paragraph 20, FERC directed NERC to "to make an informational filing within six months of the date of the issuance of this Final Rule explaining whether there is a further system protection issue that needs to be addressed and, if so, what forum and process should be used to address that issue and what priority it should be accorded relative to other reliability initiatives planned by NERC."

FERC Technical Conference

A FERC technical conference concerning the Commission's Order 754 titled Staff Meeting on Single Points of Failure on Protection Systems was held on October 24-25, 2011 at FERC in Washington, DC.

At the Technical Conference, the attendees discussed the SPF issue and narrowed their concerns into four consensus points:

- The concern with assessment of SPF is a performance-based issue, not a full redundancy issue.
- The existing approved standards address assessments of SPF.
- Assessments of SPF of non-redundant primary protection (including backup) systems need to be sufficiently comprehensive.
- Lack of sufficiently comprehensive assessments of non-redundant primary Protection Systems is a reliability concern.

Joint SPCS-SAMS Report

One outcome of the FERC Technical Conference was that NERC would conduct a data collection effort to provide a broad factual foundation that could aid in assessing the reliability risks posed by SPF. The NERC Board of Trustees approved the request for data or information under Section 1600 of the NERC Rules of Procedure ("Order No. 754 Data Request") on August 16, 2012.

In September 2015, SPCS and SAMS issued a report to the NERC PC/OC, summarizing the information collected under the Order No. 754 Data Request. The assessment confirmed the existence of a reliability risk associated

[3] *See Industry Advisory: Single Point of Failure*

with SPF in Protection Systems that warrants further action. To address this risk, the SPCS and the SAMS considered a variety of alternatives and concluded that the most appropriate recommendation that aligns with FERC Order 754 directives and maximizes reliability of Protection System performance is to modify NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The report recommendations, as well as how they have been addressed in proposed TPL-001-5 by the Project 2015-10 standard drafting team are summarized in the following section.

Revisions to TPL-001-4

Table 1-Footnote 13

The SPCS/SAMS report recommended replacing "relay" with "component of a Protection System" in the Table 1 P5 event and replace Footnote 13 in TPL-001-4 with the following alternate wording:

> The components from the definition of 'Protection System' for the purposes of this standard include (1) protective relays that respond to electrical quantities, (2) single station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), and (3) DC control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

This revision to Footnote 13 clarifies the components of the Protection System that must be considered when simulating Delayed Fault Clearing due to the failure of a non-redundant component of a Protection System. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

The SPCS/SAMS report described voltage or current sensing devices as having a lower level of risk of failure to trip due to robustness and likelihood to actually cause tripping upon failure. Therefore, these components of a Protection System are omitted from Footnote 13.

Noting that Requirements R3.3.1 and R4.3.1 require simulation of Protection System action, the drafting team sought to limit the scope of Footnote 13, item 1 with respect to protective relays that may be non-redundant components of a Protection System. Specifically, Footnote 13 limits single protective relays that may be a SPF to those which respond to electrical quantities and are used for primary protection resulting in Normal Clearing. An SPF in a single protective relay that is a non-redundant component of a Protection System may result in the primary Protection System failing to properly operate, leading to Delayed Fault Clearing performed by backup protective relays and/or overlapping zonal protection. Conversely, the drafting team did not include backup protective relays in the scope of Footnote 13, item 1 given that an SPF in a single protective relay used for backup protection will not affect primary protection resulting in Normal Clearing.

The drafting team recognizes that Bulk Electric System (BES) Elements are predominantly protected by relays which respond to electrical quantities. However, in some Protection System designs, non-redundant single protective relays which respond to electrical quantities may be redundant to protective relays that do not respond to electrical quantities. For example, an independent differential relay and independent sudden pressure relay may protect the same transformer from faults inside the transformer tank. In this example, the differential relay responds to electrical quantities, while the sudden pressure relay does not. While the transformer differential relay may be an SPF, an internal transformer tank fault may not lead to Delayed Clearing given the sudden pressure protection. Subsequently, the P5 event for a single phase-to-ground (line-to-ground) fault in the transformer tank need not be simulated for Delayed Fault Clearing due to the SPF of the transformer differential relay, but should be simulated for the sudden pressure relay clearing time, which may not be delayed. However, care must be taken when evaluating protective relays which respond to electrical quantities in combination with protective relays which do not respond to electrical quantities; in this same example, faults that occurred outside of the transformer tank given the SPF of the non-redundant transformer differential relay would be unaffected by the presence of the sudden pressure relay and would lead to delayed clearing, necessitating its assessment as a P5 event.

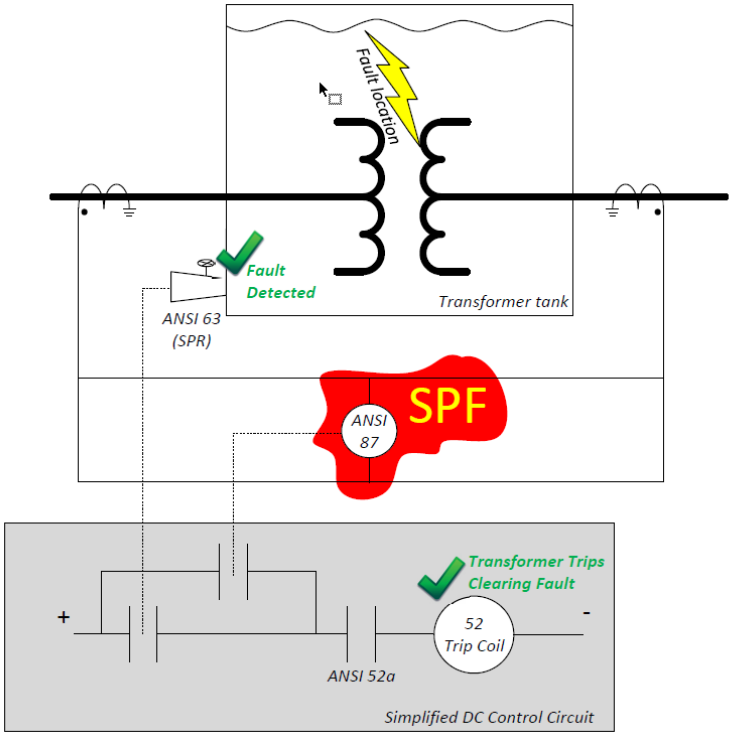


Figure 2.1: Internal Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

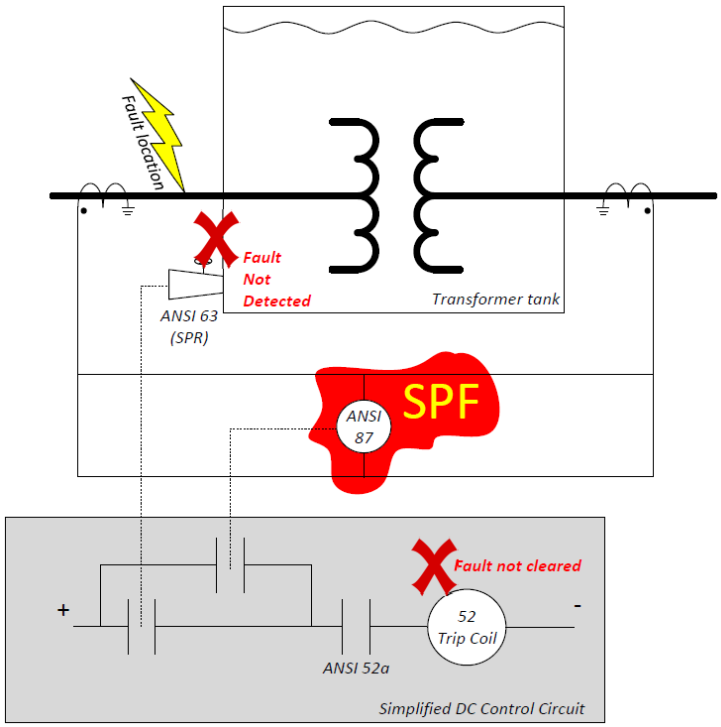


Figure 2.2: External Transformer Tank Fault with Sudden Pressure Protection and failed Transformer Differential Relay

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, line differential relaying schemes, etc.), the proper operation of the communication system must be considered when considering potential SPF components of Protection Systems. The drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning (TPL) Performance Requirements, enumerated in Table 1 of TPL-001-4. In other words, a communication-aided Protection System that may experience an SPF, causing it to operate improperly or not at all, must be considered as part of non-redundancy. The drafting team concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the Bulk Electric System is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL standards.

Requirement R4 Part 4.2 Extreme Events

Analysis of the data collected under the Order No. 754 Data Request demonstrates the existence of a reliability risk associated with SPF in Protection Systems. Further, while the analysis shows that the risk from SPF is not an endemic problem and instances of SPF exposure are lower on higher voltage systems, the risk is sufficient to warrant further action. Risk-based assessment should be used to identify Protection Systems of concern (i.e., locations on the BES where there is a susceptibility to cascading if a Protection System component SPF exists). Given the risk to BES reliability, additional emphasis in planning studies should be placed on assessment of three-phase faults involving Protection System SPF. This concern (the study of Protection System SPF) is appropriately addressed as an extreme event in TPL-001-4, Requirement R4, Part 4.2. While less probable than single-phase-to-ground faults, three-phase faults typically initiate as single-phase-to-ground and often evolve into three-phase

faults, leading to Delayed Fault Clearing scenarios more severe than the Table 1 P5 event. Therefore, TPL-001-4, Requirement R4, Part 4.5, which specifies that an evaluation of possible mitigating actions be conducted if analysis concludes there is cascading caused by the occurrence of this extreme event, is inadequate to address the risk of Protection System component SPF to the reliability of the BES. To address this concern the drafting team has modified Requirement 4 part 4.2.2 to require additional evaluation and documentation of possible actions designed to prevent the system from cascading for extreme events 2e-2h listed from the stability column of Table 1. The additional documentation shall list System deficiencies, the associated actions needed to prevent the System from Cascading, and the associated timetable for implementation. The analysis shall be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Thus, the drafting team has maintained the three-phase-fault given a Protection System component SPF as an extreme event, but modified Requirement R4, Part 4.2.2 to require additional evaluation and documentation of possible actions, including a timetable of implementation, designed to prevent the system from Cascading. This consideration is intended to account for:

- failed non-redundant components of a Protection System that may impact one or more Protection Systems;
- the duration that faults remain energized until Delayed Fault Clearing, and;
- Additional system equipment removed from service following fault clearing depending upon the specific failed non-redundant component of a Protection System.

Footnote 13 provides the attributes of the specific non-redundant Protection System components that the entity shall consider for evaluation.

Section 2: FERC Order No. 786 Directives

Background

In addition to addressing reliability issues involving SPF on Protection Systems, proposed Reliability Standard TPL-001-5 revises the TPL-001 standard to address two directives from FERC Order No. 786.

Order No. 786 P. 40: Maintenance outages in the Planning Horizon

FERC Order No. 786, Paragraph 40 directs NERC to modify Reliability Standard TPL-001-4 to address the concern that the six month threshold could exclude planned maintenance outages of significant facilities from future planning assessments. Order No. 786 provides the following considerations:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods;
- Planned outages during those times should be considered to allow for a single element to be taken out of service without compromising the ability to meet demand;
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability;
- Planned outages are not "hypothetical outages" and should not be treated as multiple contingencies in the planning standard (should be addressed in N-0 base case);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages;
- The Near-Term Transmission Planning Horizon requires annual assessments using Year One or year two and year five. Known planned facility outages of less than six months should be addressed so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon.

NERC SAMS Whitepaper Recommendations

To address this directive, the NERC SAMS recommended modifications to NERC Reliability Standards IRO-017-1 and TPL-001-4. The SAMS recommended that IRO-017-1 be used as the vehicle to assure that all types of known scheduled outages are being reviewed and coordinated to mitigate reliability impact as the most cost-effective means to address the intent of the NERC directive. The coordination process developed pursuant to IRO-017-1, Requirement R1 should be used to direct how all known scheduled outages are reviewed and the actions that must be taken. The SAMS recommended that following objectives should be added to R1:

- Describe how the review of known scheduled outages by the RC, PC, TO, and TP will be integrated into transmission plan development.
- Describe whether, how, and which known scheduled outages should be included in the Planning Assessment for the Near-Term Transmission Planning Horizon required by TPL-001-4.
- Describe how emerging challenges and the inability to schedule outages will be communicated from the TO and RC to the TP and PC to be addressed in a future Corrective Action Plan pursuant to TPL-001-4.

The NERC SAMS also recommended modifying TPL-001-4, Requirement 1.1.2 by removing "with duration of at least six months" and adding language referencing the outage coordination process developed in IRO-017-1, Requirement R1 as described above.

Revisions to TPL-001-4

Requirement R1 Part 1.1.2

The drafting team modified Requirement 1.1.2 consistent with FERC's directive and included necessary consultation with the Reliability Coordinator. This consultation is expected to assist the Transmission Planner and Planning Coordinator select known outages that are relevant, not hypothetical, and have a credible likelihood of being concurrent.

The change to Requirement 1, Part 1.1.2 eliminates the specified six month outage duration and provides the opportunity for the Reliability Coordinator to assist the Planning Coordinator and/or Transmission Planner to determine which known outages, if any, need to be considered in the Planning Assessment for the Near-Term. This change is for coordination of known outages beyond the Operations Planning time horizon.

Order No. 786 P 89: Dynamic assessment of outages of critical long lead time equipment

In paragraph 89 of Order No. 786, FERC stated:

> The spare equipment strategy for steady state analysis under Reliability Standard TPL-001-4, Requirement R2, Part 2.1.5 requires that steady state studies be performed for the P0, P1 and P2 categories identified in Table 1 with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment. The Commission believes that a similar spare equipment strategy for stability analysis should exist that requires studies to be performed for P0, P1 and P2 categories with the conditions that the system is expected to experience during the possible unavailability of the long lead time equipment.

FERC did not direct a change but did direct NERC to consider this issue upon the next review cycle of TPL-001-4. The Project 2015-10 Standard Authorization Request included this issue within the scope of this project.

NERC SAMS Whitepaper Recommendations

The NERC SAMS considered the following key points related to FERC's Paragraph 89 guidance:

- Removal of Elements in the Planning Assessment for spare equipment strategy is only applicable for those Elements that have "a lead time of one year or more."
- Each long-lead time Element that is removed from service creates a new operating condition considered the "normal" (P0) condition for Table 1. The applicable contingencies will be studied with that Element removed from service in the pre-contingency state for stability analysis. For example, if a long-lead time transformer does not have a spare, it would be studied as a P1.3 event. Since P0 does not include an Event, P0 does not and should not be included in the stability analysis section for long-lead time Elements not included as part of a spare equipment strategy.
- System adjustments may need to be made to the power flow base case to accurately reflect reasonable and expected operating conditions with that Element removed from service in the pre-contingency (P0) operating state.
- TPL-001-4, Requirement R4.1.1, related to P1 Events, requires that no generating unit pull out of synchronism. The outage of a long-lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- TPL-001-4, Requirement R4.1.2, related to P2 Events, allows for generating units to pull out of synchronism. The outage of a long-lead time Element followed by a P2 contingency should not result in

tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities.

The NERC SAMS white paper contains the flowing recommendations for stability analysis for long lead time Elements not included as part of a spare equipment strategy:

- The outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint.
- The Planning Coordinator and Transmission Planner must demonstrate that they have met the TPL-001-4 performance criteria for specified contingency events and contingency combinations thereof as per Table 1. This should include long lead time outages that can occur for equipment that does not have a spare equipment strategy.
- TPL-001-4, Requirement R4.1.1 requires that no generating unit pull out of synchronism, while R4.1.2 allows for generating units to pull out of synchronism so long as the resulting instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities. The outage of a long lead time Element followed by a P1 contingency should not result in a generating unit losing synchronism.
- While the P2 contingency allows for individual generating unit instability, the Transmission Planner and Planning Coordinator must ensure that this instability does not result in tripping of any Transmission System Elements other than the generating unit and its directly connected Facilities and therefore should include P2 contingencies event.

Revisions to TPL-001-4

Requirement R2 Part 2.4.5

Consistent with FERC's Order No. 786 guidance and the SAMS recommendations, the Project 2015-10 standard drafting team revised TPL-001-4 Requirement R2 Part 2.4.5 to add a similar requirement for stability analysis. The change to Requirement R2, Part 2.4.5, which includes similar language to that used for the steady-state analysis under R2.1.5, adds clarity that the outage of long lead time Elements has an equally important impact from a stability standpoint as it does from a steady-state standpoint and should be assessed commensurate with an entity's spare equipment strategy.

Section 3: Applicability

The requirements remain applicable to the Planning Coordinator and Transmission Planner. Coordination and cooperation between operating and planning entities in concert with asset owners will be required to implement the standard requirements. The planning and protection engineers that will need to conduct the studies and submit the data may be working for different companies or business units, and time will be required to accommodate the development of processes and data flow that cross company or business unit lines.

Generator Owners, Transmission Owners, and Distribution Providers are required to evaluate the Protection System(s) for locations on the system where a failure of a non-redundant Protection System component could result in a potential reliability risk. These entities must provide this information, as well as resulting fault clearing times, to Transmission Planners for proper study.

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Implementation Plan

Project 2015-10 Single Points of Failure
Reliability Standard TPL-001-5

Applicable Standard(s)

- TPL-001-5 – Transmission System Planning Performance Requirements

Requested Retirement(s)

- TPL-001-4 – Transmission System Planning Performance Requirements

Prerequisite Standard(s)

- None

Applicable Entities

- Planning Coordinator
- Transmission Planner

Background

Reliability Standard TPL-001-5 revises the prior version of the TPL-001 standard in three key respects:

- To address reliability issues concerning the study of single points of failure on Protection Systems, as identified in Federal Energy Regulatory Commission (FERC) Order No. 754 issued September 15, 2011, and the NERC Planning Committee System Protection and Control Subcommittee and System Analysis and Modeling Subcommittee September 2015 report titled *Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request;*
- To address directives from FERC Order No. 786 issued October 17, 2013, in which FERC approved Reliability Standard TPL-001-4; and
- To replace references to the MOD-010 and MOD-012 standards, which have been superseded by the MOD-032 Reliability Standard.

General Considerations

The 36-month implementation period for TPL-001-5 provides Planning Coordinators and Transmission Planners with time to update their annual Planning Assessments to include the new System models and studies required by the standard. This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time to develop, among other things:

- A process for coordinating with the Reliability Coordinator which known outages of generation of Transmission Facilities of less than six months shall be represented in planning studies;
- A process for establishing coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis required by the standard; and
- Additional base case models and analysis.

In addition, the implementation plan includes an additional 24 month period for the development of Corrective Action Plans under TPL-001-5 to address newly-added studies involving single points of failure on Protection Systems. This implementation period reflects consideration that Planning Coordinators and Transmission Planners will need time beyond that provided to conduct the new studies and analysis to develop processes for coordination with asset owners and protection engineers to identify appropriate Corrective Action Plan actions and establish the associated timetables for completion. This includes~~:~~

- ~~Any necessary Corrective Action Plans to address Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h required by TPL-001-5 Requirement R4 Part 4.6; and~~

~~Any~~ any necessary Corrective Action Plans to address System performance issues for studies involving Table 1 Category P5 Multiple Contingency (Fault plus non-redundant component of a Protection System failure to operate) required by TPL-001-5 Requirement R2 Part 2.7 for the following non-redundant components of a Protection System identified in TPL-001-5 Table 1 Footnote 13, items 2-4:

- A single communications system, necessary for correct operation of ~~protective functions~~ a communication-aided protection scheme required for Normal Clearing, which is not monitored or not reported;
- A single dc supply associated with protective functions, and that single station dc supply is not monitored or not reported for both low voltage and open circuit;
- A single control circuitry associated with protective functions ~~through~~including the trip coil(s) of the circuit breakers or other interrupting devices.

Lastly, the provisions related to Corrective Action Plans including Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3) are carried forward from the TPL-001-4 implementation plan.

Effective Date

TPL-001-5 – Transmission System Planning Performance Requirements

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is 36 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Date for TPL-001-5 Requirement ~~R4, Part 4.6 and Requirement~~ 2, Part 2.7 associated with Table 1 Category P5 Footnote 13 items 2, 3, and 4

~~Entities shall not be required to comply with Requirement R4, Part 4.6 until 24 months after the effective date of Reliability Standard TPL-001-5.~~

Entitles shall not be required to comply with Requirement R2, Part 2.7 for the Table 1 Category P5 planning event for the non-redundant components of a Protection System identified in footnote 13 items 2, 3, and 4 until 24 months after the effective date of Reliability Standard TPL-001-5.

Note Regarding Corrective Action Plans

For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval of TPL-001-4, or in those jurisdictions where regulatory approval is not required on the first day of the first calendar quarter 84 months after Board of Trustees adoption or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-5, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-5:

- P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)
- P2-1
- P2-2 (above 300 kV)
- P2-3 (above 300 kV)
- P3-1 through P3-5
- P4-1 through P4-5 (above 300 kV)
- P5 (above 300 kV)

Initial Performance of Periodic Requirements

Each responsible entity shall complete the first annual Planning Assessment in accordance with TPL-001-5 by the effective date of the standard.

Each responsible entity shall complete any required Corrective Action Plans under Requirement ~~R4, Part 4.6 and Requirement~~ R2, Part 2.7 associated with the non-redundant components of a

Protection System identified in Table 1 Category P5 Footnote 13 items 2, 3, and 4 by 24 months after the effective date of Reliability Standard TPL-001-5.

Retirement Date

TPL-001-4 – Transmission System Planning Performance Requirements

Reliability Standard TPL-001-4 shall be retired immediately prior to the effective date of TPL-001-5 in the particular jurisdiction in which the revised standard is becoming effective.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2015-10 Single Points of Failure TPL-001

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for Requirement R4 in Project 2015-10 and Single Points of Failure TPL-001. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justification for TPL-001-5, Requirement R1

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R1

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R2

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R2

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R3

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R3

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R4

The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R4

The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R5
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R5
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R6
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R6
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R7
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R7
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VRF Justification for TPL-001-5, Requirement R8
The VRF did not change from the previously FERC approved TPL-001-4 Reliability Standard.

VSL Justification for TPL-001-5, Requirement R8
The VSL did not change from the previously FERC approved TPL-001-4 Reliability Standard.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the ~~first~~second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	February 10- March 13, 2017
45-day formal comment period with additional ballot	July 27 – September 11, 2017
45-day formal comment period with additional ballot	October 27 – December 11, 2017

Anticipated Actions	Date
~~45-day formal comment period with additional ballot~~	~~TBD~~
10-day final ballot	TBD
Board	TBD

~~Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.~~

A. Introduction

1. **Title:** Cyber Security – Communications between Control ~~Center Communication Networks~~ Centers

2. **Number:** CIP-012-1

3. **Purpose:** To protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring and control data transmitted between Control Centers ~~required for reliable operation of the Bulk Electric System (BES).~~.

4. **Applicability:**

   4.1. Functional Entities: ~~For the purpose of the~~The requirements ~~contained herein,~~in this standard apply to the following ~~list of~~ functional entities ~~will be collectively,~~ referred to as "Responsible Entities~~." For requirements in this standard where a specific functional entity,~~" that own or ~~subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.~~operate a Control Center.

   4.1.1. Balancing Authority

   4.1.2. Generator Operator

   4.1.3. Generator Owner

   4.1.4. Reliability Coordinator

   4.1.5. Transmission Operator

   4.1.6. Transmission Owner

   4.2. **Exemptions:** The following are exempt from Reliability Standard CIP-012-1:

   4.2.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

   4.2.2. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

5. **Effective Date:** See Implementation Plan for CIP-012-1.

B. Requirements and Measures

~~Rationale for Requirements R1 and R2:~~ ~~FERC Order No. 822 directed NERC to develop modifications to the CIP Reliability Standards to require Responsible Entities to implement controls to protect communication links and sensitive Bulk Electric System (BES) data communicated between BES Control Centers. Reliability Standard CIP-012-1 responds to that directive, requiring Responsible Entities to develop a plan to protect the confidentiality and integrity of sensitive data while being transmitted between Control Centers. Responsible~~

~~Entities use various means to communicate information between Control Centers. The plan for protecting these communications is required for all impact levels due to the inter-dependency of multiple impact levels.~~

~~The type of data in scope of CIP-012-1 is data used for Operational Planning Analyses, Real-time Assessments, and Real-time monitoring. The terms Operational Planning Analyses, Real-time Assessments, and Real-time used are defined in the Glossary of Terms Used in NERC Reliability Standards and used in TOP-003 and IRO-010, among other Reliability Standards.~~

~~There are differences between the plan(s) required to be developed and implemented for CIP-012-1 and the protection required in CIP-006-6 Requirement R1 Part 1.10. CIP-012-1 Requirements R1 and R2 protect the applicable data during transmission between two geographically separate Control Centers. CIP-006 Requirement R1 Part 1.10 protects nonprogrammable communication components within an Electronic Security Perimeter (ESP) but outside of a Physical Security Perimeter (PSP). The transmission of applicable data between Control Centers takes place outside of an ESP. Therefore, the protection contained in CIP-006-6 Requirement R1 Part 1.10 does not apply.~~

R1. The Responsible Entity shall develop one or more documented plan(s) to mitigate the risk of ~~the~~ unauthorized disclosure or modification of ~~data used for Operational Planning Analysis,~~ Real-time ~~Assessments,~~Assessment and Real-time monitoring and control data while being transmitted between any Control Centers. This requirement excludes oral communications. The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** Risk mitigation shall be accomplished by one or more of the following actions:~~

- ~~Physically protecting the communication links transmitting the data;~~
- ~~Logically protecting the data during transmission; or~~

~~**1.2.**~~**1.1.** ~~Using an equally effective method~~Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of ~~the data.~~ Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers;

~~Note: If the Responsible Entity does not have a Control Center or it does not transmit the type of data specified in Requirement R1 of CIP-012-1 between two Control Centers, the requirements in CIP-012-1 would not apply to that entity.~~

1.2. Identification of demarcation point(s) where security protection is applied for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers; and

1.3. Identification of roles and responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring and control data between Control Centers, when the Control Centers are owned or operated by different Responsible Entities.

M1. Evidence may include, but is not limited to, documented plan(s) that meet the security objective of Requirement R1.

R2. The Responsible Entity shall implement the plan(s) specified in Requirement R1, except under CIP Exceptional Circumstances.

M2. Evidence may include, but is not limited to, documentation ~~to demonstrate~~demonstrating implementation of ~~methods to mitigate~~ the ~~risk of the unauthorized disclosure or modification of data in~~plans developed pursuant to Requirement R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC ~~or~~, the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The ~~applicable entity~~Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Responsible Entities shall keep data or evidence of each Requirement in this Reliability Standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The Compliance Enforcement Authority (CEA) shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	~~N/A~~ The Responsible Entity documented its plan(s) but failed to include one of the applicable parts of the plan as specified in Requirement R1.	~~N/A~~The Responsible Entity documented its plan(s) but failed to include two of the applicable parts of the plan as specified in Requirement R1.	The Responsible Entity failed to document ~~one or more~~ plan(s) ~~that achieve the security objective to mitigate the risk of unauthorized disclosure or modification of data used~~ for ~~Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted, excluding oral communication, between Control Centers as specified in~~ Requirement R1.
R2.	N/A	N/A	N/A	The Responsible Entity failed to implement its plan(s) ~~to mitigate the risk of unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time~~

				~~monitoring while being transmitted, excluding oral communication, between Control Centers~~ as specified in Requirement R1, except under CIP Exceptional Circumstances.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to FERC Order No. 822	N/A

Standard Attachments

None.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	March 9, 2016
SAR posted for comment	March 23 - April 21, 2016
SAR posted for comment	June 1 – June 30, 2016
Informal comment period	February 10- March 13, 2017
45-day formal comment period with additional ballot	July 27 – September 11, 2017
45-day formal comment period with additional ballot	October 27 – December 11, 2017

Anticipated Actions	Date
10-day final ballot	TBD
Board	TBD

A. Introduction

1. **Title:** Cyber Security – Communications between Control Centers

2. **Number:** CIP-012-1

3. **Purpose:** To protect the confidentiality and integrity of Real-time Assessment and Real-time monitoring and control data transmitted between Control Centers.

4. **Applicability:**

   4.1. Functional Entities: The requirements in this standard apply to the following functional entities, referred to as "Responsible Entities," that own or operate a Control Center.

   4.1.1. Balancing Authority

   4.1.2. Generator Operator

   4.1.3. Generator Owner

   4.1.4. Reliability Coordinator

   4.1.5. Transmission Operator

   4.1.6. Transmission Owner

   4.2. **Exemptions:** The following are exempt from Reliability Standard CIP-012-1:

   4.2.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

   4.2.2. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

5. **Effective Date:** See Implementation Plan for CIP-012-1.

B. Requirements and Measures

R1. The Responsible Entity shall develop one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between any Control Centers. This requirement excludes oral communications. The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers;

1.2. Identification of demarcation point(s) where security protection is applied for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers; and

1.3. Identification of roles and responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring and control data between Control Centers, when the Control Centers are owned or operated by different Responsible Entities.

M1. Evidence may include, but is not limited to, documented plan(s) that meet the security objective of Requirement R1.

R2. The Responsible Entity shall implement the plan(s) specified in Requirement R1, except under CIP Exceptional Circumstances.

M2. Evidence may include, but is not limited to, documentation demonstrating implementation of the plans developed pursuant to Requirement R1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC, the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

1.2. Evidence Retention: The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

The Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Responsible Entities shall keep data or evidence of each Requirement in this Reliability Standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The Compliance Enforcement Authority (CEA) shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or

information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Responsible Entity documented its plan(s) but failed to include one of the applicable parts of the plan as specified in Requirement R1.	The Responsible Entity documented its plan(s) but failed to include two of the applicable parts of the plan as specified in Requirement R1.	The Responsible Entity failed to document plan(s) for Requirement R1.
R2.	N/A	N/A	N/A	The Responsible Entity failed to implement its plan(s) as specified in Requirement R1, except under CIP Exceptional Circumstances.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to FERC Order No. 822	N/A

Standard Attachments

None.

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Implementation Plan

Project 2016-02 Modifications to CIP Standards
Reliability Standard CIP-012-1

Applicable Standard

- Reliability Standard CIP-012-1 - Cyber Security – Communications between Control ~~Center Communication Networks~~Centers

Requested Retirements

- None

Prerequisite Standard

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Generator Operator
- Generator Owner
- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Effective Date

Reliability Standard CIP-012-1 - Cyber Security – Communications between Control ~~Center Communication Networks~~Centers

Where approval by an applicable governmental authority is required, Reliability Standard CIP-012-1 shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard CIP-012-1 shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~twenty-four (24) calendar months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Project 2016-02 Consideration of Issues and Directives

Federal Energy Regulatory Commission Order No. 822

~~June 21~~October 27, 2017

Directives from FERC Order No. 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
53	53. As discussed in detail below, however, the Commission concludes that modifications to CIP-006-6 to provide controls to protect, at a minimum, communication links and data communicated between bulk electric system Control Centers are necessary in light of the critical role Control Center communications play in maintaining bulk electric system reliability. Therefore, we adopt the NOPR proposal and direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact).	The Project 2016-02 Standard Drafting Team (SDT) drafted Reliability Standard CIP-012-1 Requirement R1 to require responsible entities to document one or more plan(s) to mitigate the risk of ~~the~~ unauthorized disclosure or modification of ~~data used for Operational Planning Analysis,~~ Real-time ~~Assessments,~~Assessment and Real-time monitoring and control data while being transmitted between Bulk Electric System (BES) Control Centers. Requirement R2 requires implementation of the documented plan(s). Due to the sensitivity of the data being transmitted between the Control Centers, ~~as defined in the NERC Glossary of Terms Used in Reliability Standards,~~ the SDT created the standard ~~and determined that it applies~~to apply to all impact levels of BES Cyber Systems (i.e., high, medium, or low impact). Based on operational risk, the SDT determined that Real-time Assessments and Real-time monitoring and control data was the appropriate scope of the requirement. This critical

Directives from FERC Order No. 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
		information is necessary for immediate situational awareness and real-time operation of the BES. The SDT has drafted requirements allowing Responsible Entities the flexibility to apply protection to the communication links, the data, or both, consistent with their operational environments to satisfy the security objective of the Commission's directive~~, consistent with the capabilities of the Responsible Entity's operational environment. The directive language~~ FERC Order No. 822 specifically references CIP-006-6, which pertains to physical security controls. CIP-006-6, Requirement R1, Part 1.10 focuses on protecting the nonprogrammable communication components between Cyber Assets within the same ESP for medium and high impact BES Cyber Systems. The SDT asserts that most of the communications contemplated by ~~the~~FERC Order No. 822 are not within the same ESP, and ~~that~~, as such, CIP-006-6, Requirement R1, Part 1.10 would not be the appropriate location for this requirement.
54	54. NERC and other commenters recognize that inter-Control Center communications play a critical role in maintaining bulk electric system reliability by, among other things, helping to maintain situational awareness and reliable bulk electric system operations through	The SDT agrees that inter-Control Center communications play a critical role in Bulk Electric System reliability. Responsible Entities should therefore apply security measures to mitigate the risk of ~~the~~ unauthorized disclosure or modification of ~~data used for Operational Planning Analysis,~~ Real-time

Directives from FERC Order No. 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
	timely and accurate communication between Control Centers.[59] We agree with this assessment. In order for certain responsible entities such as reliability coordinators, balancing authorities, and transmission operators to adequately perform their reliability functions, their associated control centers must be capable of receiving and storing a variety of sensitive bulk electric system data from interconnected entities. Accordingly, we find that additional measures to protect both the integrity and availability of sensitive bulk electric system data are warranted.[60] We also understand that the attributes of the data managed by responsible entities could require different information protection controls. [61] For instance, certain types of reliability data will be sensitive to data manipulation type attacks, while other types of reliability data will be sensitive to eavesdropping type attacks aimed at collecting operational information (such as line and equipment ratings and impedances). NERC should consider the differing attributes of bulk electric system data as it assesses the development of appropriate controls. Footnotes: [59] NERC Comments at 20.	~~Assessments,~~Assessment and Real-time monitoring~~, which~~ and control data. Since the current CIP Reliability Standards do not address~~. As such~~ this, the SDT has ~~defined~~designed requirements ~~that are designed~~ to protect the data while it is being transmitted between inter-entity and intra-entity Control Centers. The SDT has drafted requirements ~~allowing~~that allow responsible entities to apply protection to the communication links, the data, or both to satisfy the security objective consistent with the capabilities of –the responsible entity's operational environment.

Directives from FERC Order No. 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
	[60] Protecting the integrity of bulk electric system data involves maintaining and ensuring the accuracy and consistency of inter-Control Center communications. Protecting the availability of bulk electric system data involves ensuring that required data is available when needed for bulk electric system operations. [61] Moreover, in order for certain responsible entities to adequately perform their Reliability Functions, the associated control centers must be capable of receiving and storing a variety of sensitive data as specified by the IRO and TOP Standards. For instance, pursuant to Reliability Standard TOP-003-3, Requirements R1, R3 and R5, a transmission operator must maintain a documented specification for data and distribute its data specification to entities that have data required by the transmission operator's Operational Planning Analyses, Real-time Monitoring and Real-time Assessments. Entities receiving a data specification must satisfy the obligation of the documented specification.	
55	55. With regard to NERC's development of modifications responsive to our directive, we agree with NERC and other commenters that NERC should have flexibility in the manner in which it addresses the Commission's directive. Likewise, we find reasonable the principles outlined by NERC that protections for communication	The SDT drafted Reliability Standard CIP-012-1 ~~to establish~~ requirements to mitigate the risk of ~~the~~ unauthorized disclosure or modification of ~~data used for Operational Planning Analysis,~~ Real-time Assessments~~,~~ and Real-time monitoring and control data while being transmitted between Control Centers. The SDT developed objective-based rather than prescriptive

Directives from FERC Order No. 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
	links and sensitive bulk electric system data communicated between bulk electric system Control Centers: (1) should not have an adverse effect on reliability, including the recognition of instances where the introduction of latency could have negative results; (2) should account for the risk levels of assets and information being protected, and require protections that are commensurate with the risks presented; and (3) should be results-based in order to provide flexibility to account for the range of technologies and entities involved in bulk electric system communications.[62] Footnote: [62] See NERC Comments at 20-21.	requirements. This approach will allow Responsible Entities flexibility in protecting these communications networks and sensitive BES data in a manner suited to each of their respective operational environments. It will also allow Responsible Entities to implement protection that considers the risks noted by the Commission. The SDT identified a need to mitigate the risk of ~~the~~ unauthorized disclosure or modification of ~~data used for Operational Planning Analysis,~~ Real-time Assessment~~,~~ and Real-time monitoring and control data regardless of asset risk level. The proposal requires protection for all ~~data used for Operational Planning Analysis,~~ Real-time Assessment~~,~~ and Real-time monitoring and control data while being transmitted between Control Centers.
56	56. We disagree with the assertion of NIPSCO and G&T Cooperatives that the risk posed by bulk electric system communication networks does not justify the costs of implementing controls. Communications between Control Centers over such networks are fundamental to the operations of the bulk electric system, and the record here does not persuade us that controls for such networks are not available at a reasonable cost (through encryption or otherwise). Nonetheless, we recognize that not all communication network components and data pose the same risk to	The SDT noted the FERC reference to additional Reliability Standards (TOP-003-3 and IRO-010-2) and the responsibilities to protect the data in accordance with those standards ~~(TOP-003-3 and IRO-010-2).~~. The SDT interpreted these references as examples of potentially sensitive BES data and chose to base the CIP-012 requirements on the data specifications in ~~these standards.~~TOP-003-3 and IRO-010-2.. This consolidates scoping and helps ensure that Responsible Entities mitigate the risk of the unauthorized disclosure or modification of ~~Operational Planning Analysis,~~ Real-time Assessment~~,~~ and Real-time monitoring and control data, rather than leaving the scoping of

Directives from FERC Order No. 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
	bulk electric system reliability and may not require the same level of protection. We expect NERC to develop controls that reflect the risk posed by the asset or data being protected, and that can be implemented in a reasonable manner. It is important to recognize that certain entities are already required to exchange necessary real-time and operational planning data through secured networks using a "mutually agreeable security protocol," regardless of the entity's size or impact level.[63] NERC's response to the directives in this Final Rule should identify the scope of sensitive bulk electric system data that must be protected and specify how the confidentiality, integrity, and availability of each type of bulk electric system data should be protected while it is being transmitted or at rest. Footnote: [63] See Reliability Standards TOP-003-3, Requirement R5 and IRO-010-2, Requirement R3.	sensitive bulk electric system data to individual Responsible Entities. The SDT drafted CIP-012-1 to address confidentiality and integrity of ~~data used for Operational Planning Analysis,~~ Real-time Assessment~~,~~ and Real-time monitoring~~. These are accommodated~~ and control data. This was accomplished by drafting the requirement to mitigate the risk from unauthorized disclosure or modification. The SDT ~~contends~~asserts that the availability of this data is already required by the performance obligation of the ~~Operating~~TOP and ~~Planning~~IRO Reliability Standards. The SDT drafted CIP-012-1 to address the data while being transmitted. The SDT contends that this data is maintained within BES Cyber Systems, and is afforded the protections of CIP-003 through CIP-011~~.~~ while at rest.
58	58. Several commenters sought clarification whether Control Centers owned by multiple registered entities would be included under the Commission's proposal. We clarify that the scope of the directed modifications apply to Control Center communications from	The SDT ~~created the standard and determined that it applies~~drafted CIP-012-1 to apply to all impact levels of BES Cyber Systems (i.e., high, medium, or low impact), regardless of ownership. The SDT ~~defined~~designed requirements ~~that are designed~~ to mitigate the risk of ~~the~~ unauthorized disclosure or

Directives from FERC Order No. 822		
Paragraph	**Directive Language**	**Consideration of Issue or Directive**
	facilities at all impact levels, regardless of ownership. The directed modification should encompass communication links and data for intra-Control Center and inter-Control Center communications.	modification of ~~data used for Operational Planning Analysis,~~ Real-time Assessment~~,~~ and Real-time monitoring and control data while being transmitted between inter-entity and intra-entity BES Control Centers.
62	62. Several commenters addressed encryption and latency. Based on the record in this proceeding, it is reasonable to conclude that any lag in communication speed resulting from implementation of protections should only be measureable on the order of milliseconds and, therefore, will not adversely impact Control Center communications. Several commenters raise possible technical implementation difficulties with integrating encryption technologies into their current communications networks. Such technical issues should be considered by the standard drafting team when developing modifications in response to this directive, and may be resolved, e.g., by making certain aspects of the revised CIP Standards eligible for Technical Feasibility Exceptions.	The SDT developed objective-based rather than prescriptive requirements. This approach will allow Responsible Entities flexibility in mitigating the risk of ~~the~~ unauthorized disclosure or modification of ~~data used for Operational Planning Analysis,~~ Real-time Assessments~~,~~ and Real-time monitoring data in a manner suited to each of their respective operational environments. It will also allow Responsible Entities to implement protection that considers the risks noted by the Commission.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2016-02 Modifications to CIP Standards

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **CIP-012-1**. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to Bulk Electric System instability, separation, or a cascading sequence of failures, or could place the Bulk Electric System at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System. However, violation of a medium risk requirement is unlikely to lead to Bulk Electric System instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to Bulk Electric System instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement
A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor and control the Bulk Electric System; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report

FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief.

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

VSLs define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs.

VSLs should be based on NERC's overarching criteria shown in the table below:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC Order of Violation Severity Levels

The FERC VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline (1) – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline (2) – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline (3) – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline (4) – Violation Severity Level Assignment Should Be Based on a Single Violation, Not on a Cumulative Number of Violations

Unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF Justifications for CIP-012-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium was assigned to this requirement. Cyber security plans enable effective implementation of the CIP standard's requirements to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted between Control Centers.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirement complements CIP-005-1, Requirement R1, CIP-006-6, Requirement R1, and CIP-007-6, Requirement R1 which are related to security of networks and communications components. The proposed VRF is consistent with these related requirements.
FERC VRF G4 Discussion Guideline 4- Consistency with NERC Definitions of VRFs	Failure to have a cyber security plan would not, under Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion	N/A

VRF Justifications for CIP-012-1, Requirement R1	
Proposed VRF	**Medium**
Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	

VSLs for CIP-012-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	~~N/A~~ The Responsible Entity documented its plan(s) but failed to include one of the applicable parts of the plan as specified in Requirement R1.	~~N/A~~The Responsible Entity documented its plan(s) but failed to include two of the applicable parts of the plan as specified in Requirement R1.	The Responsible Entity failed to document ~~one or more~~ plan(s) ~~that achieve the security objective to mitigate the risk of the unauthorized disclosure or modification of data used~~ for ~~Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted, excluding oral communication, between Controls Centers as specified in~~ Requirement R1.

VSL Justifications for CIP-012-1 Requirements R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL does not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	~~The proposed VSL is binary and is classified as severe. The VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.~~The requirement is for the Responsible Entity to document include one or more plans as specified in Requirement R1. The moderate VSL addresses where the Responsible Entity documented its plan(s) but failed to include one of the applicable parts of the plan as specified in Requirement R1. The high VSL addresses where the Responsible Entity documented its plan(s) but failed to include two of the applicable parts of the plan as specified in Requirement R1. The severe VSL addresses where the Responsible Entity failed to document plan(s) for Requirement R1.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, therefore, consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	~~The~~Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for CIP-012-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium was assigned to this requirement. Implementation of required cyber security plans enable effective implementation of the CIP standard's requirements to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted between Control Centers.
FERC VRF G1 Discussion Guideline 1- Consistency with Blackout Report	N/A
FERC VRF G2 Discussion Guideline 2- Consistency within a Reliability Standard	N/A
FERC VRF G3 Discussion Guideline 3- Consistency among Reliability Standards	The requirement complements CIP-005-1, Requirement R1, CIP-006-6, Requirement R1, and CIP-007-6, Requirement R1 which are related to security of networks and communications components. The proposed VRF is consistent with these related requirements.
FERC VRF G4 Discussion	Failure to properly implement the cyber security plan would not, under Emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state

VRF Justifications for CIP-012-1, Requirement R2	
Proposed VRF	**Medium**
Guideline 4- Consistency with NERC Definitions of VRFs	or capability of the Bulk Electric System, or the ability to effectively monitor, control, or restore the Bulk Electric System.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	N/A

VSLs for CIP-012-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Responsible Entity failed to implement its plan ~~to mitigate the risk of the unauthorized disclosure or modification of data used for Operational, Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted, excluding oral communication, between Controls Centers~~(s) as specified in Requirement R1, except under CIP Exceptional Circumstances.

VSL Justifications for CIP-012-1 Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSL does not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is binary and is classified as severe. The VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, therefore, consistent with the requirement.

FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is based on a single violation and not cumulative violations.

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Reliability Standard Audit Worksheet[1]

CIP-012-1 – Cyber Security – Communications between Control Centers~~Control Center Communication Networks~~

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	PA/PC	RC	RP	RSG	TO	TOP	TP	TSP
R1	X		X	X		X			X	X		
R2	X		X	X		X			X	X		

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The RSAW may provide a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserve the right to request additional evidence from the registered entity that is not included in this RSAW. This RSAW may include excerpts from FERC Orders and other regulatory references which are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

DRAFT

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

DRAFT

Registered Entity Response (Required):

Question 1[A1][A2]**:** Does the Registered Entity own or operate a Control Center? ☐ Yes ☐ No

If no:

1. Provide evidence in the space that the Registered Entity does not own or operate one or more Control Centers. This evidence may include, but is not limited to:
   - Evidence that the Registered Entity does not own or operate a Control Center; or
   - Evidence or a reference to evidence from the Registered Entity's CIP-002 compliance program that demonstrates the entity does not own or operate a Control Center.
   - ~~Evidence that the Registered Entity's asset list does not contain a Control Center.~~
2. The remainder of this RSAW may be left blank.

~~If yes, continue with Question 2.~~

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

~~**Question 2:** Is data used for Operational Planning Analysis, Real-time Assessments, or Real-time monitoring and control transmitted between Control Centers at any time by any Control Center owned or operated by the Registered Entity? ☐ Yes ☐ No~~

~~If no:~~

~~Provide evidence in the space below supporting this assertion. This evidence may include, but is not limited to:~~

- ~~Evidence demonstrating data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring and control is not transmitted between Control Centers at any time by any Control Center owned or operated by the Registered Entity.~~

~~1. The remainder of this RSAW may be left blank.~~

~~If yes, continue with the remainder of this RSAW.~~

~~[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]~~

R1 Supporting Evidence and Documentation

R1. The Responsible Entity shall develop one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between any Control Centers. This requirement excludes oral communications. The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers;

1.2 Identification of demarcation point(s) where security protection is applied for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers; and

1.3 Identification of roles and responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring and control data between Control Centers, when the Control Centers are owned or operated by different Responsible Entities.

~~The Responsible Entity shall develop one or more documented plan(s) to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring while being transmitted between Control Centers. This excludes oral communications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**1.1** Risk mitigation shall be accomplished by one or more of the following actions:~~

- ~~Physically protecting the communication links transmitting the data;~~
- ~~Logically protecting the data during transmission; or~~
- ~~Using an equally effective method to mitigate the risk of unauthorized disclosure or modification of the data.~~

~~Note: If the Responsible Entity does not have a Control Center or it does not transmit the type of data specified in Requirement R1 of CIP-012-1 between two Control Centers, the requirements in CIP-012-1 would not apply to that entity.~~

M1. Evidence may include, but is not limited to, documented plan(s) that meet the security objective of Requirement R1.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

DRAFT

Compliance Assessment Approach Specific to CIP-012-1, R1

This section to be completed by the Compliance Enforcement Authority

	If the Registered Entity has answered "No" to ~~either~~ Question 1 ~~or Question 2~~, verify~~:~~ ~~The~~the Registered Entity does not own or operate a Control Center. Note: If the Registered Entity does not own or operate a Control Center, the remainder of this RSAW is not applicable.~~; or~~ ~~The Registered Entity does not transmit data used for Operational Planning Analysis, Real-time Assessments, or Real-time monitoring and control at any time between Control Centers.~~
	Verify the entity has developed one or more documented plan(s) to mitigate the risk of the unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers.
	Verify the documented plans collectively include identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers.
	Verify the documented plans collectively include identification of demarcation point(s) where security protection is applied for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers.~~; and~~
	~~If the Registered Entity has answered "Yes" to Question 2, verify:~~ ~~The entity has developed one or more documented plans to mitigate the risk of the unauthorized disclosure or modification of data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring and control data while being transmitted between Control Centers; and~~ ~~The documented plans collectively include identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers; and~~ ~~The documented plans collectively include identification of demarcation point(s) where security protection is applied for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers; and~~ Verify the ~~The~~ documented plans collectively include identification of roles and responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring and control data between Control Centers, when the Control Centers are owned or operated by different Responsible Entities. ~~The documented plan(s) collectively address all data used for Operational Planning Analysis, Real-time Assessments, and Real-time monitoring transmitted between Control Centers; and~~ ~~The documented plan(s) collectively accomplish risk mitigation by one or more of the following actions:~~ ~~Physically protecting the communication links transmitting the data;~~ ~~Logically protecting the data during transmission; or~~ ~~Using an equally effective method to mitigate the risk of unauthorized disclosure or modification of the data.~~
	Verify the documented plans collectively achieve the security objective of mitigating the risk of the unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers.
Note to Auditor: 1. Oral communications are not in scope for CIP-012-1.	

Auditor Notes:

DRAFT

R2 Supporting Evidence and Documentation

R2. The Responsible Entity shall implement the plan(s) specified in Requirement R1, except under CIP Exceptional Circumstances.

M2. Evidence may include, but is not limited to, documentation to demonstrate implementation of methods to mitigate the risk of the unauthorized disclosure or modification of data in Requirement R1.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to CIP-012-1, R2

This section to be completed by the Compliance Enforcement Authority

	~~If the Registered Entity has answered "Yes" to Question 2, verify with system-generated evidence (where available) that the Registered Entity has implemented the plan(s) specified in Requirement R1, except under CIP Exceptional Circumstances.~~
	Verify the entity has implemented one or more documented plan(s) to mitigate the risk of the unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers.
	Verify the entity has identified security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers.
	Verify the entity has identified demarcation point(s) where security protection is applied for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers;

	and
	Verify the entity has identified roles and responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring and control data between Control Centers, when the Control Centers are owned or operated by different Responsible Entities.
	If the Responsible Entity has declared and responded to CIP Exceptional Circumstances, verify the Responsible Entity has adhered to the applicable cyber security policies.
Note to Auditor: The Responsible Entity may reference a separate set of documents to demonstrate its response to any requirements impacted by CIP Exceptional Circumstances.	

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Auditor Notes:

DRAFT

Additional Information:

Reliability Standard

The full text of CIP-012-1 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Standards," "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology

Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language

FERC Order 822 P53-56, 58, and 62

Selected Glossary Terms

The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

CIP Exceptional Circumstance

A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.

Control Center

One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

~~Operational Planning Analysis~~

~~An evaluation of projected system conditions to assess anticipated (pre-Contingency) and potential (post-Contingency) conditions for next-day operations. The evaluation shall reflect applicable inputs including, but~~

~~not limited to, load forecasts; generation output levels; Interchange; known Protection System and Special Protection System status or degradation; Transmission outages; generator outages; Facility Ratings; and identified phase angle and equipment limitations. (Operational Planning Analysis may be provided through internal systems or through third-party services.)~~

Real-time Assessment

An evaluation of system conditions using Real-time data to assess existing (pre-Contingency) and potential (post-Contingency) operating conditions. The assessment shall reflect applicable inputs including, but not limited to: load, generation output levels, known Protection System and Special Protection System status or degradation, Transmission outages, generator outages, Interchange, Facility Ratings, and identified phase angle and equipment limitations. (Real-time Assessment may be provided through internal systems or through third-party services.)

Real-time

Present time as opposed to future time.

DRAFT

Revision History for RSAW

Version	Date	Reviewers	Revision Description
Draft1 v1	07/28/2017	NERC Stds Group	New document
Draft1 v2	08/01/2017	RSAW Task Force	Modified Question to clarify applicability
Draft1 v3	08/02/2017	RSAW Task Force	Response to MRO comments. Moved Questions 1 and 2 above R1. Made text changes to Q1 and to R2 Compliance Assessment Approach.
Draft1 v4	08/07/2017	RSAW Task~~f~~ Force, 2016-02 SDT	Response to TexasRE and SDT comments. Clarified scope of Q1 to be data transmitted between Control Centers. Removed extra space from Auditor Notes.
Draft2 v1	10/27/2017	RSAW Task Force	Modified title. Modified Q2 to conform with new language. Modified R1 with new Requirement text and new Compliance Assessment Approach. Modified R2 with new Compliance Assessment Approach. Removed Operational Planning Analysis from the Selected Glossary Terms. Modified footer with revised version and date.
Draft2 v2	11/27/2017	RSAW Task Force	Response to comments: • RF: Footnote 1 page 1 added space after "references." • RF: Changed "Tasf" to "Task" in Revision History • Response to SERC CIPC and Southern Company comments to Draft 1. • Modified Question 1 to include reference to CIP-002. • Added an item to the R1 Compliance Assessment Approach to verify the effectiveness of the process. • Modified the R2 Compliance Assessment Approaches to clarify that the review is for implementation.

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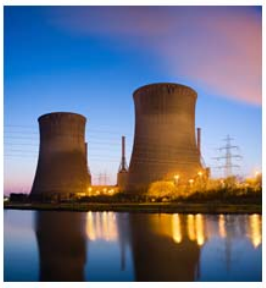
DRAFT

Cyber Security – Communications Between Control Centers

Implementation Guidance for CIP-012-1

RELIABILITY | ACCOUNTABILITY



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Introduction

The Commission issued Order No. 822 on January 21, 2016. Order 822 approved seven CIP Reliability Standards and new or modified definitions, and directed modifications be made to the CIP Reliability Standards. Among other items, the Commission directed NERC to "develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)." (Order 822, Paragraph 53)

In response to the directive in Order No. 822, the Project 2016-02 standard drafting team (SDT) drafted Reliability Standard CIP-012-1 to require Responsible Entities to implement controls to protect sensitive Bulk Electric System (BES) data and communications links between BES Control Centers. Due to the sensitivity of the data being communicated between Control Centers, the standard applies to all impact levels (i.e., high, medium, or low impact).

The SDT drafted requirements to provide Responsible Entities the latitude to protect the communication links, the data, or both, to satisfy the security objective consistent with the capabilities of the Responsible Entity's operational environment. Requirement R1 requires Responsible Entities to document one or more plans that protect Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers. The plan(s) must address how the Responsible Entity will mitigate the risk of unauthorized disclosure or modification of the applicable data. Requirement R2 covers implementation of the plan developed according to Requirement R1.

The Project 2016-02 SDT also drafted this Implementation Guidance document to provide examples of approaches to comply with CIP-012-1. Implementation Guidance does not prescribe the only approach, but is intended to highlight one or more approaches that would be effective ways to be compliant with the standard. As Implementation Guidance is only meant to provide examples, entities may choose alternative approaches that better fit their situation[1].

Responsible Entities may find it useful to consider this Implementation Guidance document along with the additional context and background provided in the SDT developed Technical Rationale and Justification for CIP-012-1 document.

[1] NERC's Compliance Guidance Policy

Requirements

R1. *The Responsible Entity shall develop one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between any Control Centers. This requirement excludes oral communications. The plan shall include: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers;

1.2. Identification of demarcation point(s) where security protection is applied for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers; and

1.3. Identification of roles and responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring and control data between Control Centers, when the Control Centers are owned or operated by different Responsible Entities.

R2. *The Responsible Entity shall implement the plan(s) specified in Requirement R1, except under CIP Exceptional Circumstances.*

General Considerations

General Considerations for R1

As noted in the Technical Rationale and Justification for CIP-012-1, the focus of Requirement R1 is on developing a plan to protect information that is critical to the real-time operations of the Bulk Electric System while in transit between applicable Control Centers. The number of plan(s) and their content may depend on a Responsible Entity's management structure and operating conditions. The Responsible Entity may document as many plans as necessary to meet its needs. For instance, a Responsible Entity may choose to document one plan per Control Center or it may choose to document everything in a single plan. A Responsible Entity may choose to document one plan for communications between Control Centers it owns and a separate plan for communications between its Control Centers and the Control Centers of a neighboring Entity. The number and structure of the plans is at the discretion of the Responsible Entity as long as the plan(s) include the required elements described in parts 1.1, 1.2, and 1.3 of Requirement 1.

Identification of Security Protection

Entities have latitude to determine which security protections are used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers and should identify those protections accordingly.

This security protection could consist of logical protection, physical protection, or some combination of both. To determine security protection, the requirement specifies that it must mitigate the risk of unauthorized disclosure or modification of applicable data.

Identification of Demarcation Point(s)

A Responsible Entity should consider its environment to determine an effective solution when identifying the demarcation points where security protections are applied. One approach to identifying a demarcation point is to place the demarcation point within the Control Center so the confidentiality and integrity of the data is protected throughout the transmission. The Responsible Entity can choose either a physical or logical demarcation point. Demarcation points identified by the Responsible Entity do not add additional assets to the scope of the CIP Reliability Standards. The demarcation point identification ensures that each Responsible Entity identifies clear demarcation of where the protection is applied to the in-scope data. Demarcation points may vary based on many factors such as impact levels of the Control Center, different technologies, or infrastructures.

Identification of Roles and Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities

The Technical Rationale and Justification for CIP-012-1 identifies key considerations in the Control Center Ownership section when communicating between Control Centers with different owners or operators. Most if not all of the many relationships between Responsible Entities are unique. Consequently, there is no single way to identify roles and responsibilities for applying security protection to the transmission of Real-time Assessment and Real-time monitoring and control data between Control Centers. Responsible Entities may consider identifying the roles and responsibilities for the following situations: (1) configuration of security protocols, (2) responding to communication failures, and (3) responding to Cyber Security Incidents.

General Considerations for R2

Given the format of the requirements, the majority of the documentation is required under R1 while R2 requires the implementation of the plan developed for R1. Compliance with R2 is established by implementing the protection identified in a Responsible Entity's R1 plan. The sections below outline examples of evidence that may be provided in order to demonstrate the implementation of Entity Alpha's CIP-012-1 R1 plan.

Identification of Security Protection

Implementation of the security protection can be demonstrated in many ways. If physical protection is used, a Responsible Entity may demonstrate implementation through a floor plan which identifies the physical security measures in place protecting the communication link. If logical protection is used, a Responsible Entity may demonstrate implementation through an export of the device configuration which applies the security protection. Alternatively, a Responsible Entity may demonstrate implementation through monitoring of the security control such as a report generated from an automated tool that monitors the encryption service used to protect a communications link.

Identification of Demarcation Point(s)

Identification of demarcation point(s) could be demonstrated with a diagram (physical or logical) or a list. This diagram or list could be included within the plan developed for R1. A label could also be used to identify a device as a demarcation point.

Identification of Roles and Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities

Implementation of roles and responsibilities could also be demonstrated in many ways. Some examples include a joint procedure, a memorandum of understanding or meeting minutes between the two parties where roles and responsibilities are discussed.

Reference Models

For this Implementation Guidance, the SDT considers a basic reference model of Primary and Backup Control Centers (Entity Alpha) to illustrate concepts necessary to demonstrate compliance. These Control Centers communicate to each other and to a neighboring entity's Control Center (Entity Beta) in configurations outlined by the diagrams in this section. The SDT recognizes that the reference models do not contain many of the complexities of a real Control Center. For this Implementation Guidance, the registration or functions performed in the reference model Control Center are also not considered. A high level block diagram of the basic reference model is shown below in Figure 1. This Implementation Guidance is developed from the perspective of Entity Alpha.

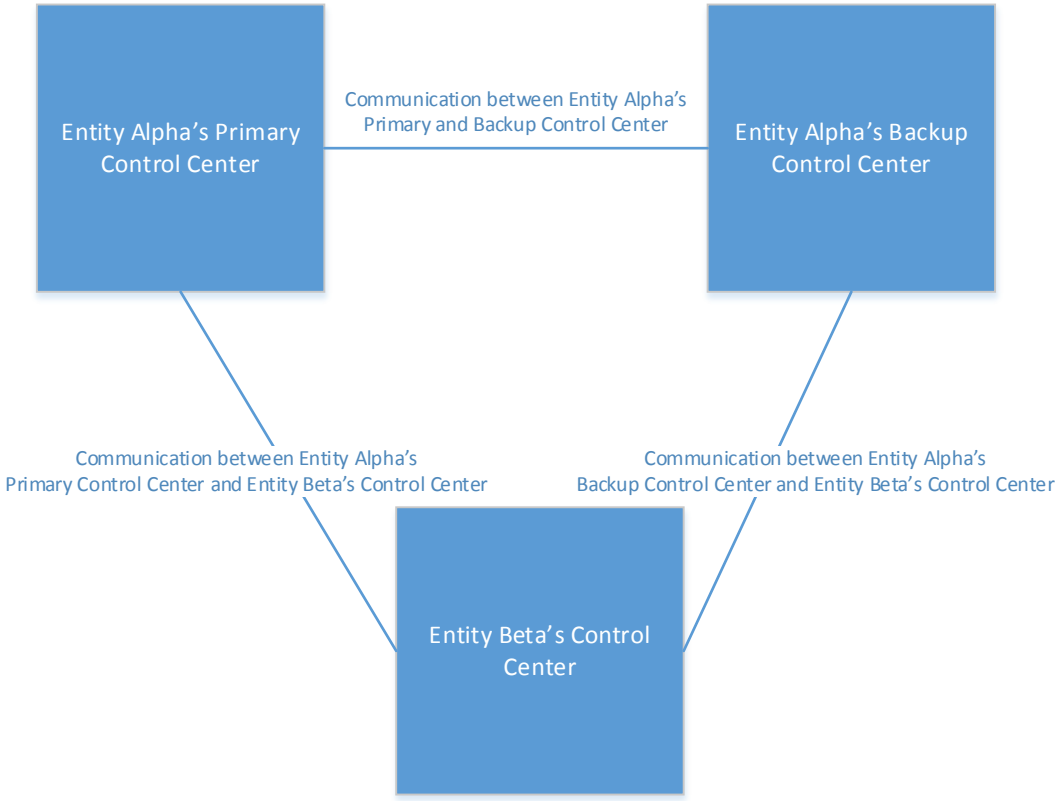

Figure 1: High Level Block Diagram of Reference Model Control Centers

Reference Model Discussion for Requirement R1

Requirement R1 requires the development of a documented plan. To comply with requirement R1, one approach to a plan is to first determine which communications require protection pursuant to CIP-012-1. There are multiple ways to identify an entity's scope in R1. For example, Entity Alpha in the reference model may first identify the Control Centers with which it communicates. Entity Alpha would determine that there are three: Entity Alpha's Primary Control Center, Entity Alpha's Backup Control Center, and Entity Beta's Control Center. Entity Alpha does not need to consider whether Entity Beta further shares its data with another Entity. That is the responsibility of Entity Beta and is outside of Entity Alpha's purview. Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. These communications are out of scope for CIP-012-1.

Now that Entity Alpha has identified the Control Centers with which it communicates, Entity Alpha identifies either: (1) the Real-time Assessment and Real-time monitoring and control data; or (2) communication links which are used to transmit Real-time Assessment and Real-time monitoring and control data between Control Centers. In either case, Entity Alpha may find it useful to refer to the data specification for Real-time

Assessment and Real-time monitoring data identified in TOP-003-3 and IRO-010-2. For this reference model scenario, identifying the communication links used to transmit Real-time Assessment and Real-time monitoring and control data may be the most straightforward approach. Through an evaluation of communication links between Control Centers and an evaluation of how it transmits and receives Real-time Assessment and Real-time monitoring and control data, Entity Alpha determined that it communicates applicable data between its primary and backup Control Centers across a single communication link. Entity Alpha also determined that it communicates applicable data to and from Entity Beta's Control Center across one of two links that originate from either Entity Alpha's primary or backup Control Center using the Inter-Control Center Communications Protocol (ICCP).

With an identified scope of communications links, Entity Alpha now considers the three required elements of its required communications between Control Centers for its plan.

Identification of Security Protection

- Entity Alpha must ensure that protection is applied at the CIP-012-1 demarcation point. The protection must also meet the security objective of mitigating the risk of unauthorized disclosure or modification of applicable data while in transit between Control Centers for the entire distance between CIP-012-1 demarcation points. In a simple case where the demarcation point is sufficiently close to the Control Center, such as within the Physical Security Perimeter of the Control Center, Entity Alpha may use a single security protection method to meet the security objective. For this case, shown in Figure 2, Entity Alpha documents in its plan that it uses a Virtual Private Network (VPN) connection across a private leased communication circuit for each of its three in-scope communication links. To meet the security objective, Entity Alpha further states that its VPN uses Internet Protocol security (IPsec) with AES-128 encryption.
- For more complex scenarios, Entity Alpha may need to use a combination of security controls. For instance, in Figure 3, Entity Alpha uses a combination of physical security controls (physical access control) and logical security controls (encrypted communications consistent with the first scenario above) to meet the security objective.
- The complexity increases when Entity Alpha and Entity Beta exchange data through a 3rd party, such as in Figure 4. In this scenario, Entity Alpha again uses a combination of logical controls. First, encrypted communications are used between the CIP-012-1 demarcation point at Entity Alpha and extended to the 3rd party WAN router. Then, a number of security controls may be leveraged such as network segmentation and system access control to protect the data as it transits the 3rd party network. Finally, encrypted communications is used again to protect the data as it transits between the 3rd party network and the CIP-012-1 demarcation point at Entity Beta.
- While these scenarios are all specific to communication links, it is possible that Entity Alpha and Entity Beta achieve the security objective by applying protection to the data rather than the communication links. In this scenario, the application enabling the data exchange between Control Centers may be capable of applying security controls directly to the data. These security controls mitigate the risk of unauthorized disclosure or modification of applicable data rather than relying on lower level network services to provide this security. For instance, Entity Alpha and Entity Beta may apply security protection at the application layer by using Secure ICCP to exchange applicable data. According to a report released by Sandia National Labs[2], Secure ICCP provides "data integrity indirectly by providing a cryptographic checksum…Secure ICCP provides data confidentiality by encrypting ICCP data exchanges." Methods other than Secure ICCP could also be used to apply security protection to the data at the application layer.
- It is theoretically possible that Entity Alpha and Entity Beta could exchange Real-time Assessment data between Control Centers by email. In that scenario, one approach may be for Entity Alpha to email the

[2] https://energy.gov/sites/prod/files/oeprod/DocumentsandMedia/19-Secure_ICCP_Integration.pdf

applicable data to Entity Beta's Control Center in a protected container such as an encrypted zip file. Entity Alpha and Entity Beta can then exchange the password to that encrypted container through another method, such as by phone. While the notional example of protecting data exchanged by email is a useful illustration of how to achieve the security objective of CIP-012-1, it is extremely unlikely to be used in practice. The characteristics of email communication are inconsistent with the requirements of Real-time data exchange.

Identification of Demarcation Point(s)

- Figure 2 shows the identification of CIP-012-1 demarcation points for the Entity Alpha reference model. Entity Alpha has identified its demarcation point at each of its Control Centers to be the external Ethernet interface on the WAN router where the security protection is applied. It has also coordinated with Entity Beta to identify a similar demarcation point at Entity Beta's Control Center.
- In some cases, it may be helpful to identify both the CIP-012-1 demarcation points and the telecommunications carrier (telco) demarcation point. Figure 3 provides such an example where the telco demarcation point may not be within the Control Center. In this scenario, Entity Alpha identifies the CIP-012-1 demarcation point to be a point on the communications path adjacent to the outside interface on the ESP firewall. Entity Alpha has also identified the telco demarcation point at a point in the telecommunications cabling connecting to Entity Alpha's WAN router, perhaps at a punch down block for example. In Figure 3, the telco demarcation point is inside the same room as the WAN router. The telco demarcation points are referenced in the drawing for clarity, but are not part of the plan.
- Figure 4 shows the identification of possible CIP-012-1 demarcation points and telco demarcation points when Entity Alpha and Entity Beta transmit the applicable data through a third party.
- The data-centric scenario described above is less intuitive for identifying demarcation points. If security protection is applied at the application layer (such as Secure ICCP), Entity Alpha could reasonably identify the application or service applying the security (such as the Secure ICCP service) as the demarcation point.

Identification of Roles and Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities

Entity Alpha and Entity Beta may determine they each are responsible for one end of the VPN configuration on their respective WAN routers. Entity Alpha and Entity Beta have agreed to a 30 character pre-shared key for IPSec authentication and have exchanged contact information for their Network Operations Centers to enable a coordinated response to any communication failures. They have also exchanged contact information for their Security Operations Centers to enable a coordinated response to any suspected Cyber Security Incidents.

Rather than use a pre-shared key, Entity Alpha and Entity Beta may decide to use digital certificates for the IPSec authentication using a trusted certificate authority. In that scenario, Entity Alpha and Entity Beta would agree on who is the party responsible for managing the certificate authority.

When using a third party as shown in Figure 4, Entity Alpha and Entity Beta will need to define who is responsible for each part of the connection between them. Each entity may determine they are responsible for only the connection from their CIP-012-1 demarcation point to the telco demarcation point at the 3rd party. The 3rd party may take responsibility for protecting the data transiting its network.

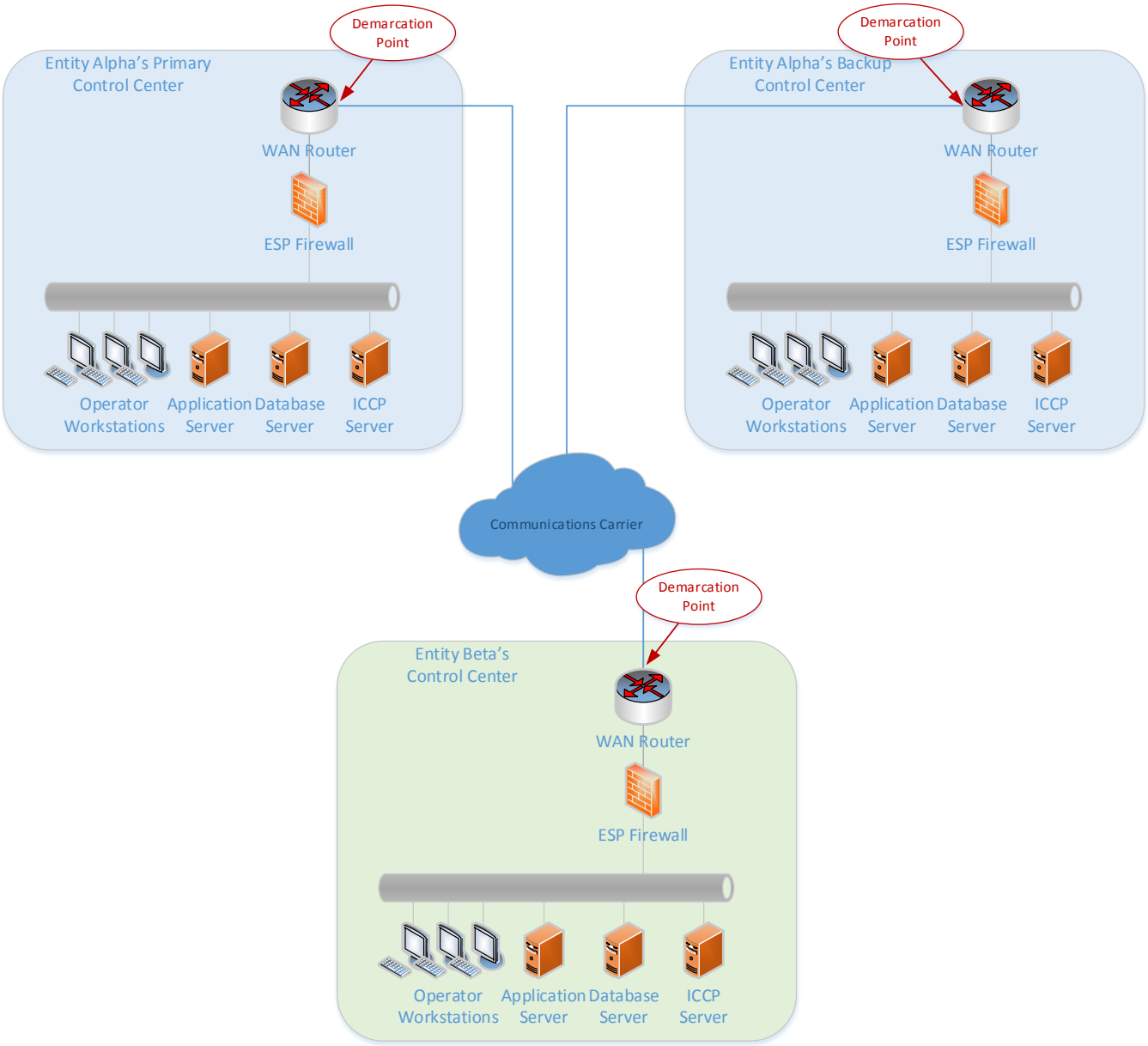

Figure 2: Network diagram and identification of demarcation points

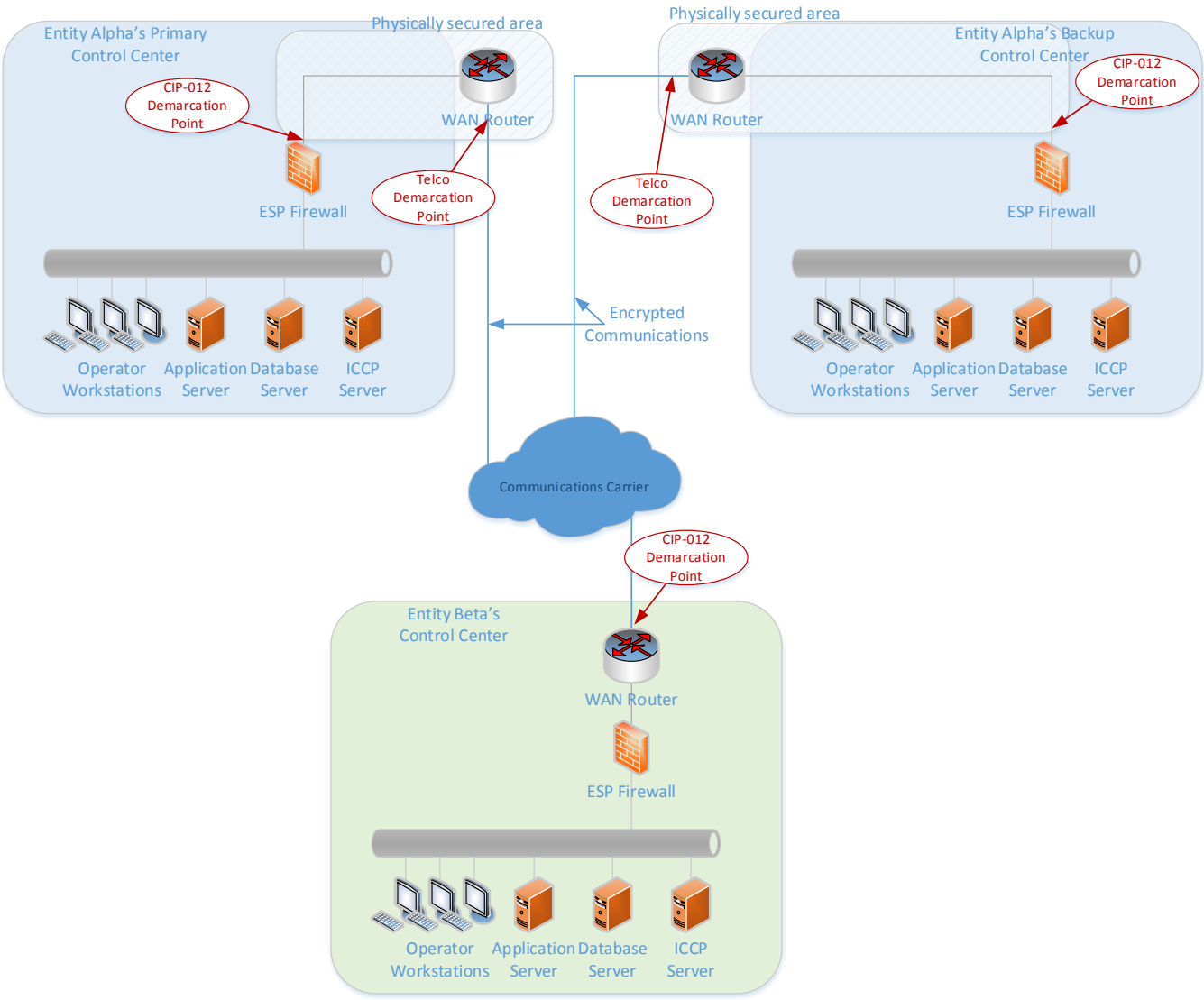

Figure 3: Network diagram using a combination of controls for CIP-012-1

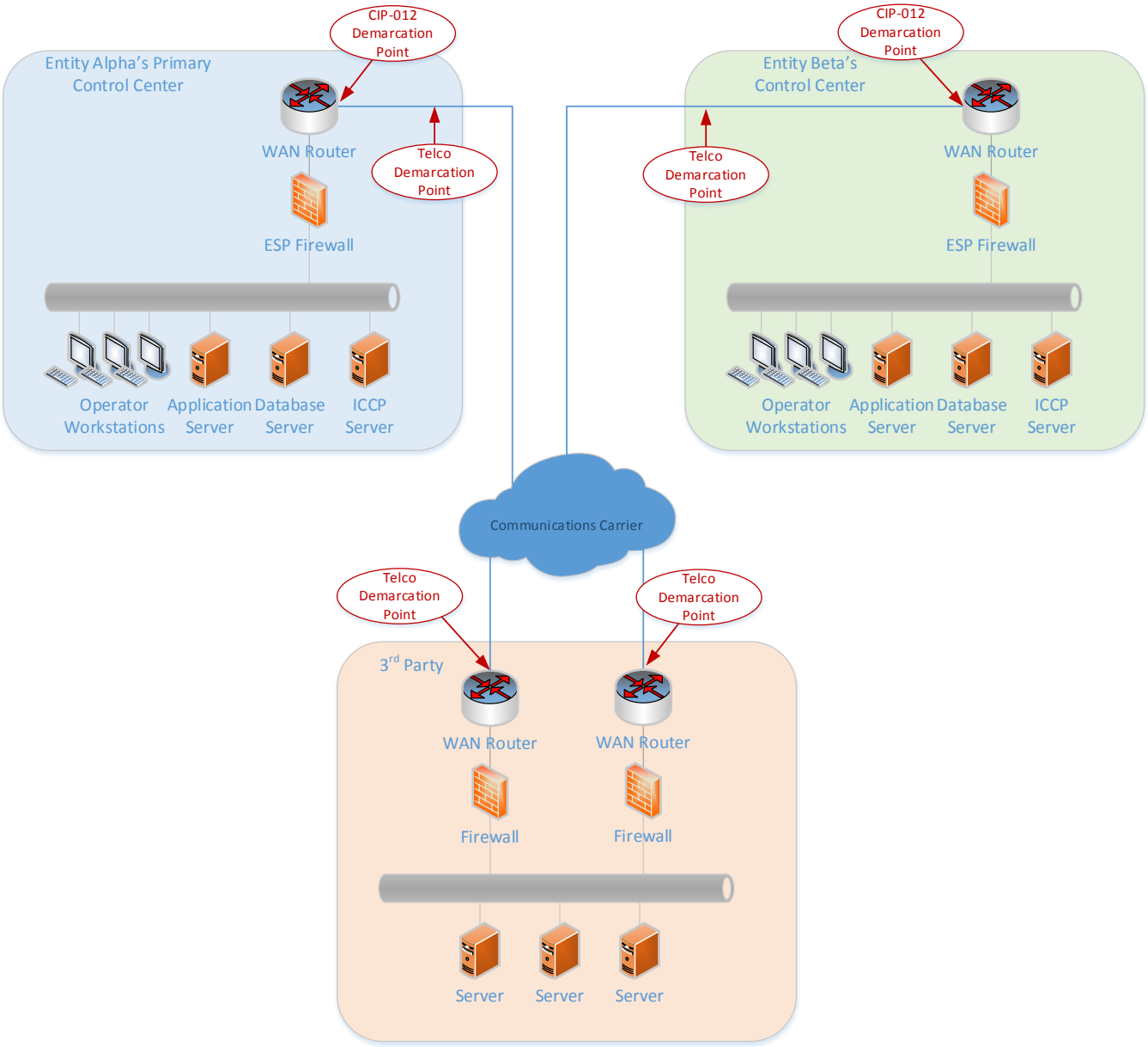

Figure 4: Network Diagram depicting communications through a 3rd party

Reference Model Discussion for Requirement R2

Entities must demonstrate implementation of their R1 plan. The sections below outline examples of evidence that may be provided to demonstrate the implementation of Entity Alpha's CIP-012-1 R1 plan.

Identification of Security Protection

Entity Alpha may demonstrate security protection implementation through the WAN router configuration which shows that a site-to-site IPSec VPN with AES-128 encryption is in place.

When physical security controls are used, Entity Alpha may demonstrate the implementation of physical protection using a floorplan diagram showing the physical access controls in place.

Identification of Demarcation Point(s)

Entity Alpha may demonstrate the identification of demarcation points through a network diagram very similar to that shown in Figure 2.

Identification of Roles and Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities

Entity Alpha may demonstrate the implementation of roles and responsibilities with Entity Beta through a memorandum of understanding (MOU) signed by both parties.

References

Mitre Common Weakness Enumeration (CWE™) list of software weakness types
https://cwe.mitre.org/data/definitions/327.html

Cryptographic Standards and Guidelines
https://csrc.nist.gov/Projects/Cryptographic-Standards-and-Guidelines

NIST Special Publication 800-175B
Guideline for Using Cryptographic Standards in the Federal Government: Cryptographic Mechanisms
http://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.800-175B.pdf

Guide to Cryptography
https://www.owasp.org/index.php/Guide_to_Cryptography#Symmetric_Cryptography

DRAFT

Cyber Security – Communications Between Control Centers

Technical Rationale and Justification for Reliability Standard CIP-012-1

November 2017

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Introduction

On January 21, 2016, the Federal Energy Regulatory Commission (FERC or Commission) issued Order No. 822, approving seven Critical Infrastructure Protection (CIP) Reliability Standards and new or modified terms in the Glossary of Terms Used in NERC Reliability Standards, and directing modifications to the CIP Reliability Standards. Among others, the Commission directed the North American Electric Reliability Corporation (NERC) to "develop modifications to the CIP Reliability Standards to require Responsible Entities[1] to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)." (Order 822, Paragraph 53)

In response to the directive in Order No. 822, the Project 2016-02 standard drafting team (SDT) drafted Reliability Standard CIP-012-1 to require Responsible Entities to implement controls to protect sensitive Bulk Electric System (BES) data and communications links between BES Control Centers. Due to the sensitivity of the data being communicated between Control Centers, as defined in the Glossary of Terms Used in NERC Reliability Standards, the standard applies to all impact levels (i.e., high, medium, or low impact).

Although the Commission directed NERC to develop modifications to CIP-006, the SDT determined that modifications to CIP-006 would not be appropriate. There are differences between the plan(s) required to be developed and implemented for CIP-012-1 and the protection required in CIP-006-6 Requirement R1 Part 1.10. CIP-012-1 Requirements R1 and R2 protect the applicable data during transmission between two separate Control Centers. CIP-006 Requirement R1 Part 1.10 protects nonprogrammable communication components within an Electronic Security Perimeter (ESP) but outside of a Physical Security Perimeter (PSP). The transmission of applicable data between Control Centers takes place outside of an ESP. Therefore, the protection contained in CIP-006-6 Requirement R1 Part 1.10 does not apply.

The SDT drafted requirements to provide Responsible Entities the latitude to protect the communication links, the data, or both, to satisfy the security objective consistent with the capabilities of the Responsible Entity's operational environment. Requirement R1 requires Responsible Entities to document one or more plans that protect Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers. The plan(s) must address how the Responsible Entity will mitigate the risk of unauthorized disclosure or modification of the applicable data. Requirement R2 covers implementation of the plan developed according to Requirement R1.

This technical rationale and justification document explains the technical rationale for the proposed Reliability Standard. It will provide stakeholders and the ERO Enterprise with an understanding of the technology and technical requirements in the Reliability Standard. It also contains information on the SDT's intent in drafting the requirements.

[1] As used in the CIP Standards, a Responsible Entity refers to the registered entities subject to the CIP Standards.

Requirement R1

R1. The Responsible Entity shall develop one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between any Control Centers. This requirement excludes oral communications. The plan shall include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1 Identification of security protection used to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers;

1.2 Identification of demarcation point(s) where security protection is applied for transmitting Real-time Assessment and Real-time monitoring and control data between Control Centers; and

1.3 Identification of roles and responsibilities of each Responsible Entity for applying security protection to the transmission of Real-time Assessment and Real-time monitoring and control data between Control Centers, when the Control Centers are owned or operated by different Responsible Entities.

General Considerations for Requirement R1

Requirement R1 focuses on developing a plan to protect information that is critical to the real-time operations of the Bulk Electric System while in transit between applicable Control Centers.

Overview of confidentiality and integrity

The SDT drafted CIP-012-1 to address confidentiality and integrity of Real-time Assessment and Real-time monitoring and control data. This is accomplished by drafting the requirement to mitigate the risk of unauthorized disclosure (confidentiality) or modification (integrity). For this Standard, the SDT relied on the definitions of confidentiality and integrity as defined by National Institute of Standards and Technology (NIST):

- Confidentiality is defined as, "Preserving authorized restrictions on information access and disclosure, including means for protecting personal privacy and proprietary information."[2]
- Integrity is defined as, "Guarding against improper information modification or destruction, and includes ensuring information non-repudiation and authenticity."[3]

The SDT asserts that the availability of this data is already required by the performance obligation of the Operating and Planning Reliability Standards. The SDT drafted CIP-012 to address the data while being transmitted. The SDT maintains that this data resides within BES Cyber Systems, and while at rest is protected by CIP-003 through CIP-011.

Alignment with IRO and TOP standards

The SDT recognized the FERC reference to additional Reliability Standards and the responsibilities to protect the applicable data in accordance with NERC Reliability Standards TOP-003 and IRO-010. The SDT used these references to drive the identification of sensitive BES data and chose to base the CIP-012 requirements on the Real-time data specification elements in these standards. This approach provides consistent scoping of identified data, and does not require each entity to devise its own list or inventory of this data. Many entities are required to provide this data under agreements executed with their RC, BA or TOP, often without benefit of knowing how those entities use that data.

[2] NIST Special Publication 800-53A, Revision 4, page B-3

[3] NIST Special Publication 800-53A, Revision 4, page B-6

The SDT notes that it expanded the phrase “Real-time monitoring” data from TOP-003 and IRO-010 to “Real-time monitoring and control” data. The SDT was concerned that data transmitted between Control Centers that results in the physical operation of BES Elements was not explicitly included in Real-time monitoring data. The SDT understands that in practice Real-time control data is not transmitted separately from Real-time monitoring data. However, the SDT wanted to ensure that Real-time control data was included regardless of whether or not it is transmitted along with Real-time monitoring data. If entities only transmit Real-time control data along with Real-time monitoring data, then the SDT does not intend for such entities to identify additional data beyond that Real-time monitoring data already included in the data specifications for TOP-003 and IRO-010.

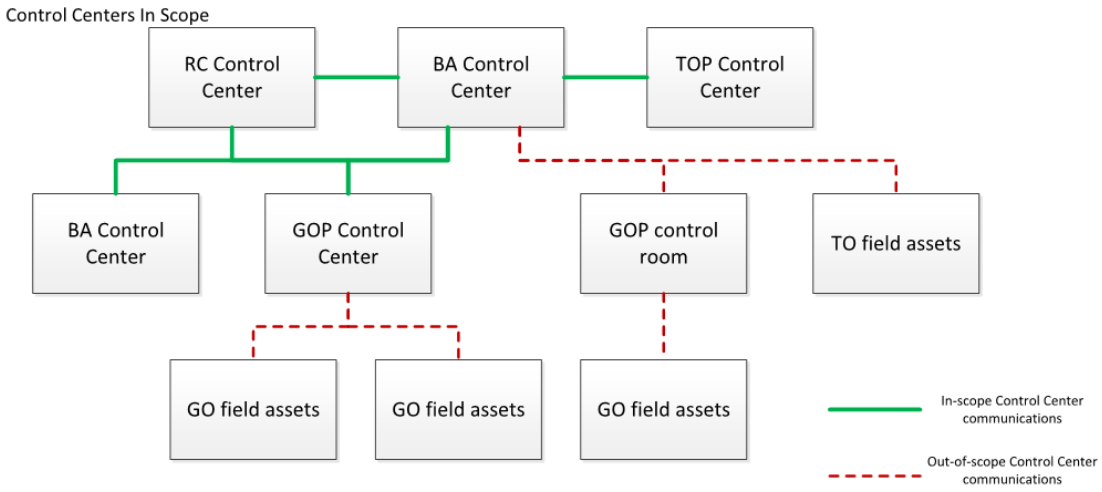
Demarcation Points

The SDT noted the need for an entity to identify a demarcation point inside each Control Center where it will apply protection for applicable data. The SDT used the demarcation point concept for implementing protection to ensure entities could still take advantage of security measures, such as deep packet inspection, already implemented at or near the EAP when ESPs are present, while maintaining the capability to protect the applicable data being transmitted between Control Centers.

Control Center Ownership

The requirements address protection for Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers owned by a single Responsible Entity. They also cover the applicable data transmitted between Control Centers owned by two or more separate Responsible Entities. Unlike protection between a single Responsible Entity’s Control Centers, applying protection between Control Centers owned by more than one Responsible Entity requires additional coordination. The requirements do not explicitly require formal agreements between Responsible Entities partnering for protection of applicable data. It is strongly recommended, however, that these partnering entities develop agreements, or use existing ones, to define responsibilities to ensure adequate protection is applied. An example noted in FERC Order No. 822 Paragraph 59 is, “if several registered entities have joint responsibility for a cryptographic key management system used between their respective Control Centers, they should have the prerogative to come to a consensus on which organization administers that particular key management system."

As an example, the reference model below depicts some of the data transmissions between Control Centers that a Responsible Entity should consider to be in-scope. The example does not include all possible scenarios. The green solid lines are in-scope communications. The red dashed lines are out-of-scope communications.



This reference model is an example and does not include all possible scenarios.

Requirement R2

R2. The Responsible Entity shall implement the plan(s) specified in Requirement R1, except under CIP Exceptional Circumstances.

General Considerations for R2

Responsible Entities can achieve the security objective of Requirement R1 through a variety of methods or combinations of methods, such as site to site encryption, application layer encryption, physical protection, etc. The protection must be designed to prevent unauthorized disclosure or modification of applicable data on the applicable communication methods between Control Centers identified in Requirement R1.1. The Responsible Entity has the discretion to implement any type of protection that meets the security objective.

References

Here are several references to assist entities in developing plan(s) for protection of communication links:

- NIST Special Publication 800-53A, Revision 4: Security and Privacy Controls for Federal Information Systems and Organizations
- NIST Special Publication 800-82: Guide to Industrial Control Systems (ICS) Security
- NIST Special Publication 800-175B: Guideline for Using Cryptographic Standards in the Federal Government: Cryptographic Mechanisms
- NIST Special Publication 800-47: Security Guide for Interconnecting Information Technology Systems

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	September 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-~~1~~2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-~~1~~2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

~~5.~~ **Background:**

6. After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

~~**7.1. Effective Date:** See Implementation Plan~~

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-~~1~~2 – Attachment 1: Relay Settings.

C. Compliance

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

8. Compliance Monitoring Process

8.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

8.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

8.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

8.4. Additional Compliance Information

None

~~Table of Compliance Elements~~

:

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-~~1~~2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

~~E. Interpretations~~

~~F.~~E. Associated Documents

NERC System Protection and Control Subcommittee, ~~July 2010, "~~"Considerations for Power Plant and Transmission System Protection Coordination~~."~~," technical reference document, Revision 2. (Date of Publication: July 2015)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, “IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers.” (Date of Publication: September 18, 2012)

IEEE C37.2-2008, “IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.” (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	

~~PRC-025-1~~2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay ~~pickup~~ setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay ~~pickup~~ setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For ~~the application case~~applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads~~.),)~~, the ~~pickup~~ setting criteria shall be determined by vector summing the ~~pickup~~ setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with ~~deenergized~~de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative

assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for ~~Special Protection Systems~~Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of ~~fullload~~full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect ~~transformer~~ overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 ~~beginning on the next page~~below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU

[3] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~. Elements may also supply generating plant loads).~~). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the ~~applied~~ application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text~~.~~, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and ~~pickup~~ setting criteria in the fourth and fifth column, respectively. The bus voltage column and ~~pickup~~ setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Synchronous generating unit(s), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~),~~ or ~~(~~51V-R~~)~~ – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	~~The same application continues with a different relay type below~~			
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Asynchronous generating unit(s) (including inverter-based installations), ~~or~~including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50, 51~~),~~ or ~~(~~51V-R~~)~~ – voltage-restrained~~)~~	~~5~~5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage

A different application starts on the next page

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 14~~ [5]	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 15~~ [6]	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 16~~ [7]	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[7] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 17~~[8]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 18~~[9]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	~~The same application continues on the next page with a different relay type~~			

[8] If the relay is installed on the high-side of the GSU transformer use Option 17.
[9] If the relay is installed on the high-side of the GSU transformer use Option 18.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
	Phase directional ~~time~~ overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer ~~If the relay is installed on the high-side of the GSU transformer use Option 19~~[10]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts ~~below~~on the next page				
Unit auxiliary transformer(s) (UAT)	Phase ~~time~~ overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
~~A different application starts on the next page~~				

[10] If the relay is installed on the high-side of the GSU transformer use Option 19.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. (Elements may also supply generating plant loads.) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system —installed on the high-side of the GSU transformer ~~If the relay is installed~~ and on the ~~generator-side~~remote end of ~~the GSU transformer use Option 7~~line[11]	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		~~OR~~		
		~~14b~~	~~Simulated line voltage coincident with the highest Reactive Power output achieved during field forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field forcing~~	~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field forcing as determined by simulation~~
	~~The same application continues on the next page with a different relay type~~			

[11] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. — connected to synchronous generators~~	~~Phase overcurrent supervisory element (50) — associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer or phase time overcurrent relay (51) — installed on the high-side of the GSU transformer~~ ~~If the relay is installed on the generator-side of the GSU transformer use Option 8~~	~~15a~~	~~0.85 per unit of the line nominal voltage~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output — 100% of the aggregate generation gross MW reported to the Transmission Planner, and~~ ~~(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor~~
		OR		
		~~15b~~14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The ~~overcurrent~~impedance element shall be set ~~greater~~less than ~~115% of~~ the calculated ~~current~~impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit	Phase ~~directional~~instantaneous overcurrent supervisory element (~~67~~e.g., 50) – associated with current-based, communication-	~~16a~~15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
or generating plant~~.~~ (Elements may also supply generating plant ~~load.~~ loads) – connected to synchronous generators	assisted schemes where the scheme is capable of tripping for loss of communications ~~directional toward the Transmission system~~ installed on the high-side of the GSU transformer and remote end of the line and/or phase ~~directional~~ time overcurrent relay (~~67) – directional toward the Transmission system~~e.g., 51) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator-side of the GSU transformer use Option 9~~and remote end of the line[12]	15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant load.) – connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line[13]	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage ~~on~~at the ~~high-side terminals~~remote end of the ~~generator step-up transformer~~line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[13] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system– installed on the high-side of the GSU transformer ~~If the relay is installed~~ and on the ~~generator-side~~remote end of ~~the GSU transformer use Option 10~~line[14]	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[14] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**~~Pickup~~ Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator side of~~ and on the ~~GSU transformer use Option 11~~remote end of the line[15]	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)

Table 1. Relay Loadability Evaluation Criteria				
Application	Relay Type	Option	Bus Voltage[4]	~~Pickup~~ Setting Criteria
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ (Elements may also supply generating plant loads~~.~~) – connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase directional time overcurrent relay (e.g., 67) – installed on the high-side of the GSU transformer ~~If the relay is installed on the generator side of~~ and on the ~~GSU transformer use Option 12~~remote end of the line[16]	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[16] If the relay is installed on the generator-side of the GSU transformer use Option 12.

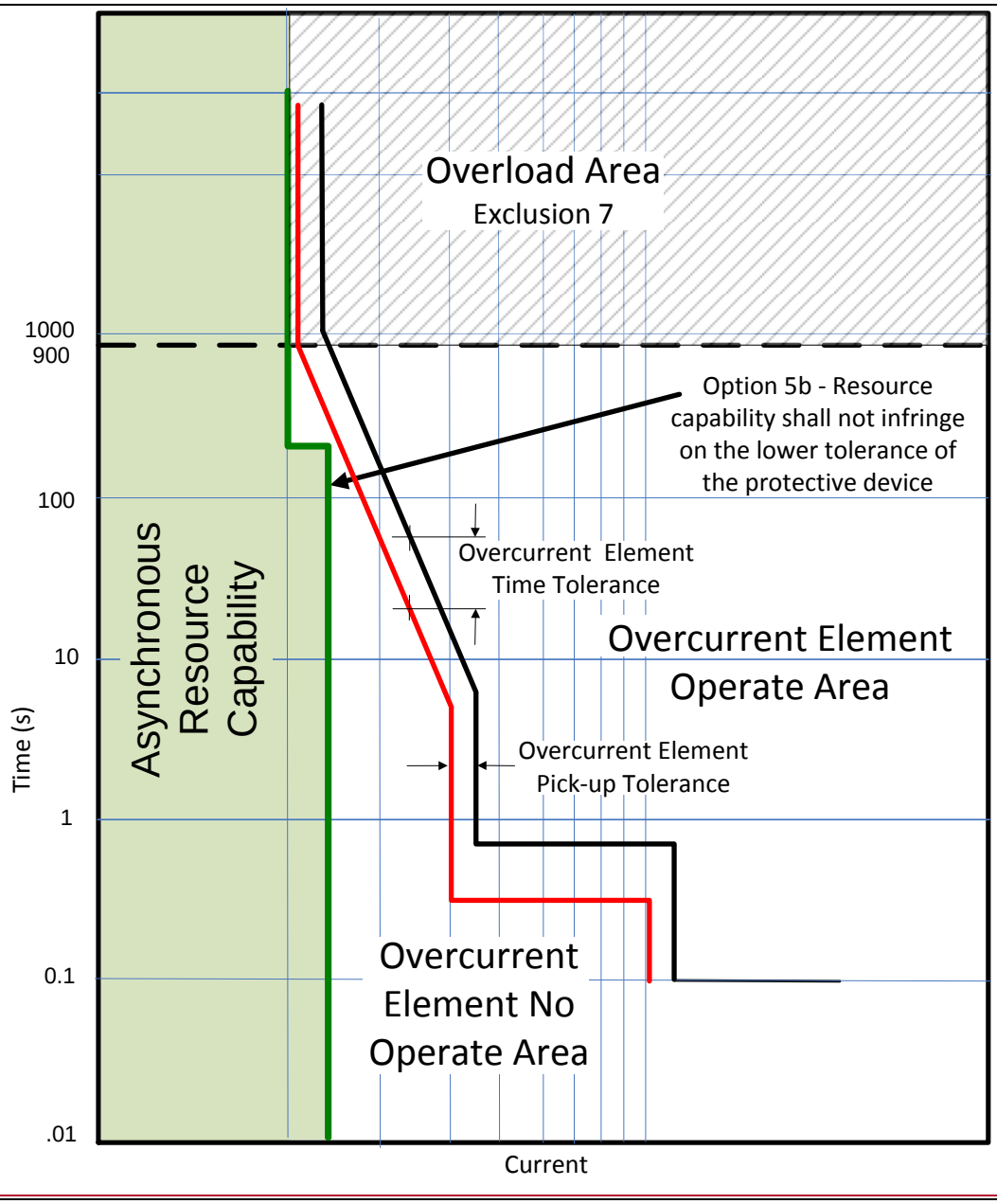


Figure A. This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-~~1~~2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July ~~2010~~2015.[17]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard

[17] ~~http://www.nerc.com/docs/pc/spctf/Gen%20Prot%20Coord%20Rev1%20Final%2007-30-2010.pdf~~
http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf

is not intended to result in the loss of these protection functions. Instead, it is suggested that the Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.
For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

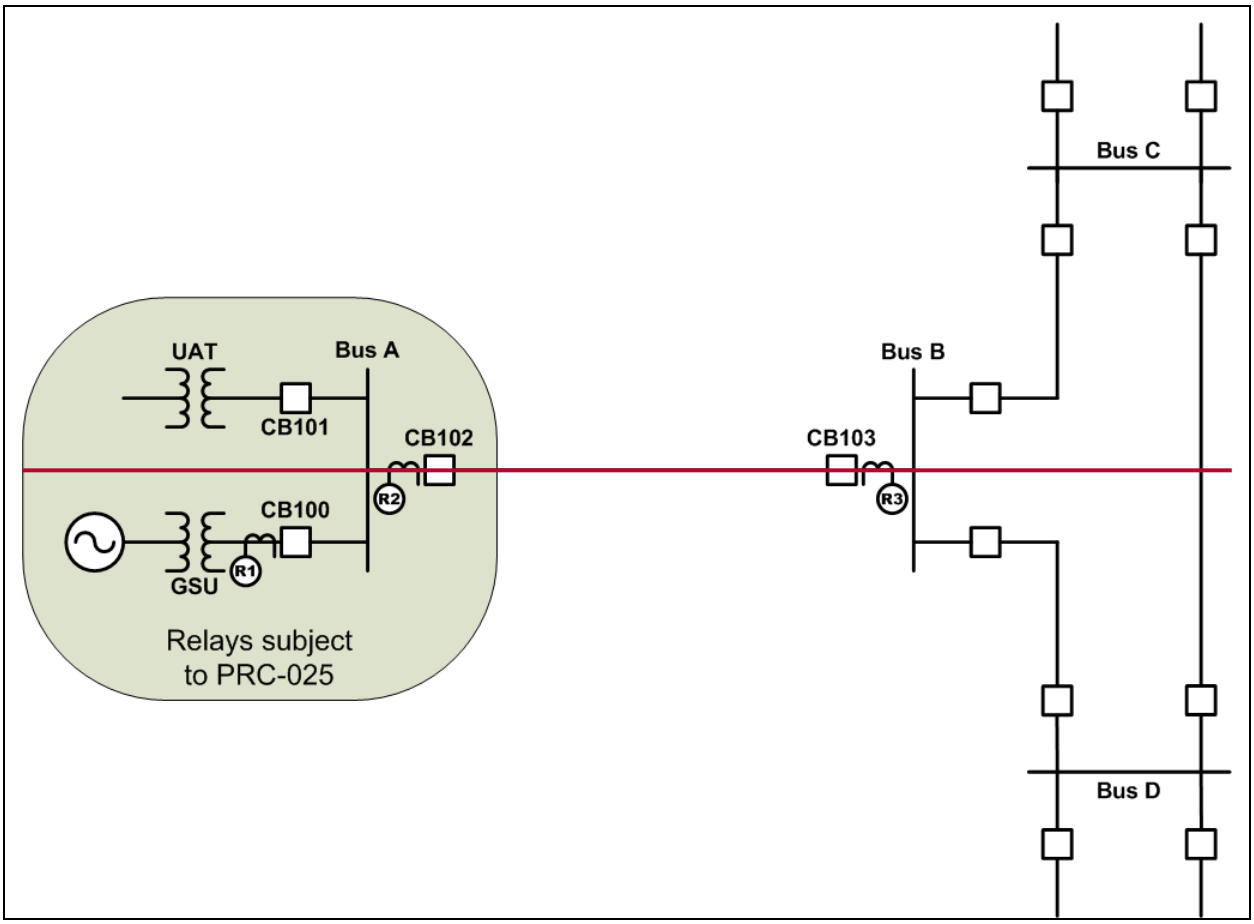
Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

~~In this particular case, the applicable responsible entity's directional relay R3 located on breaker CB103 at Bus B looking toward Bus A (i.e., generation plant) is not included in either loadability standard (i.e., PRC-023 or PRC-025) since it is not affected by increased generator output in response to system disturbances described in this standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R3, for example, if the relay is applied and set to trip for a reverse element directional toward the Transmission system.~~


UAT
Bus A
CB101
CB102
CB100
R2
R1
GSU
Relays subject
to PRC-025
Bus B
CB103
R3
Bus C
Bus D

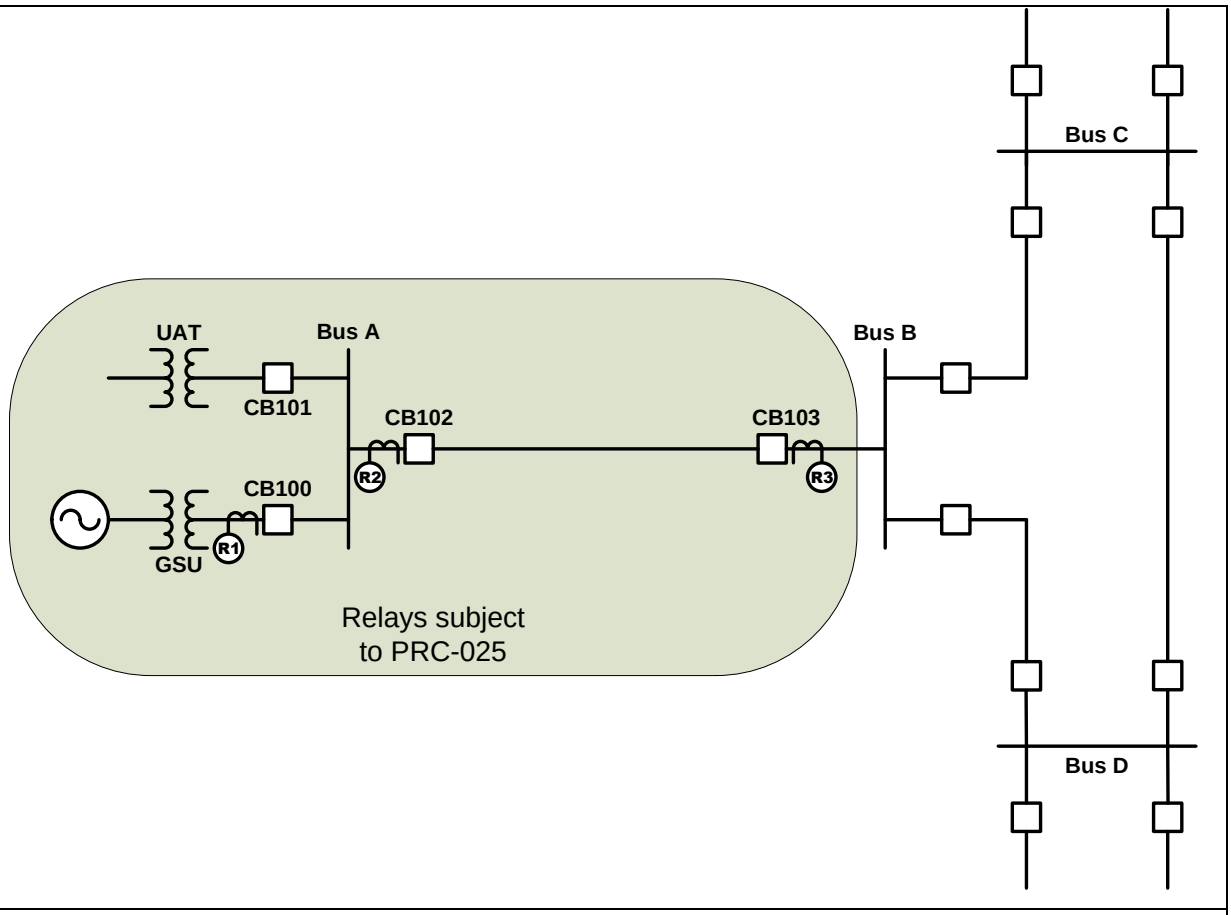


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-~~1~~2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current

differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-~~1~~2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

~~In this particular case, the applicable responsible entity's directional relay R4 and R5 located on the breakers CB104 and CB105, respectively at Bus B looking into the generation plant are not included in either loadability standard (i.e., PRC-023 or PRC-025) since they are not subject to the stressed loading requirements described in the standard or by increased transmission system loading described in PRC-023. Any protective element set to protect in the direction from Bus A to B is included within the PRC-025-1 standard. PRC-025-1 is applicable to Relay R4 and R5, for example, if the relays are applied and set to trip for a reverse element directional toward the Transmission system.~~

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

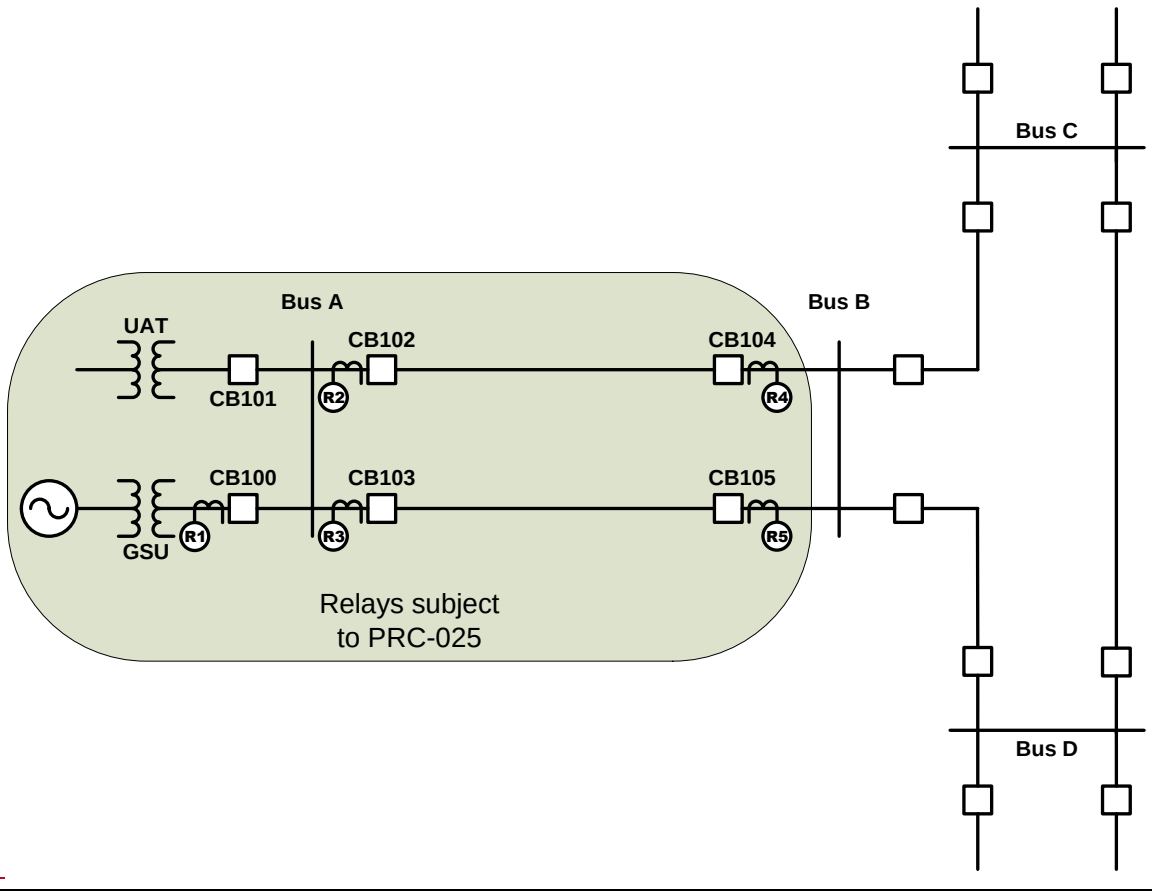


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-~~1~~2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

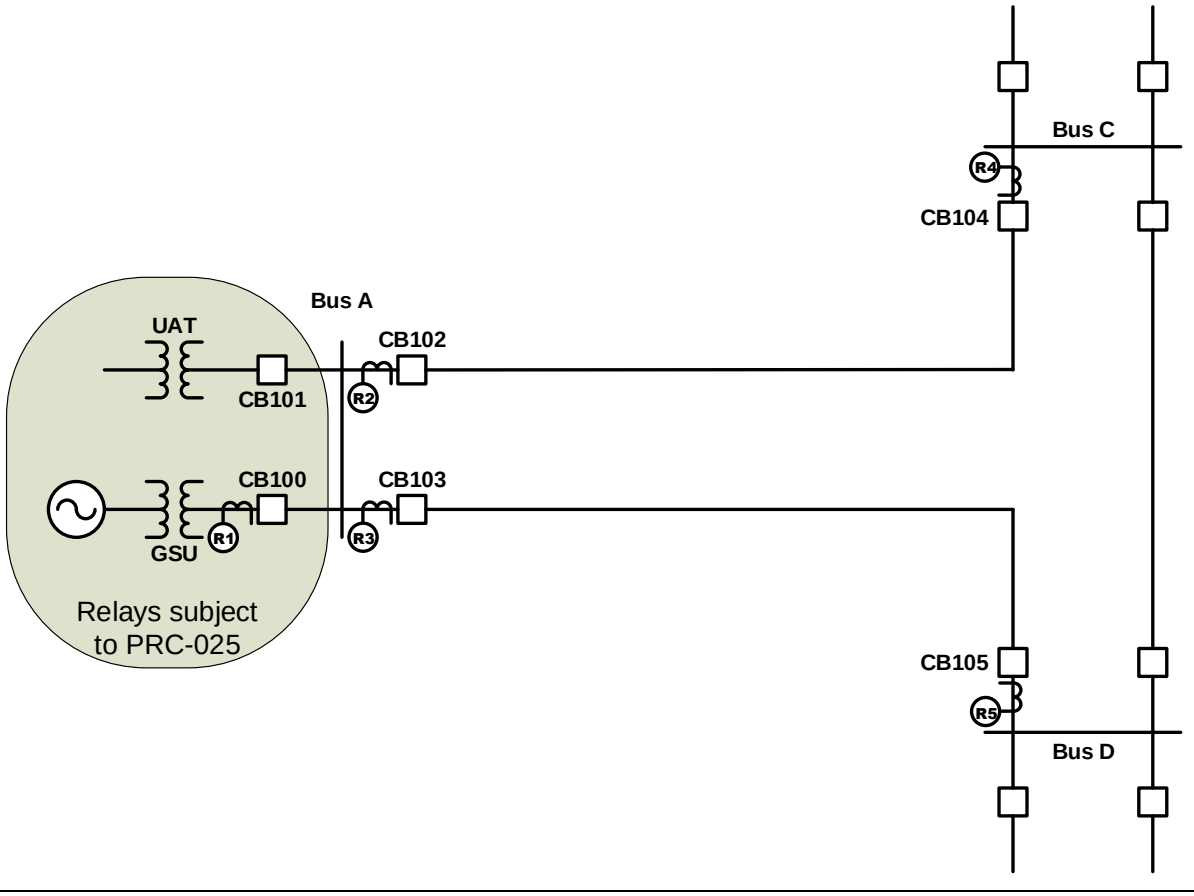


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of

the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of ~~Transmission system~~the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had ~~not~~ other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "~~Pickup~~ Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line

during a system disturbance; therefore, all output load-responsive protective ~~elements~~relays associated with the facility are included in PRC-~~-~~025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-~~1~~2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-~~1~~2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the "terminal" is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators~~, however, do not have excitation systems and~~ will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before ~~a crowbar function~~limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage ~~on~~at the

remote end of the line or at the high-side of the GSU transformer~~.~~ (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor ~~on~~at the ~~Transmission system to lower~~remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay ~~pickup~~ setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, ~~contributing~~which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to*

clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."*

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the ~~Table 1~~ setting criteria established within the Table 1 options ~~differ~~differs from ~~section 3.9.2 of~~ the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. ~~See section 3.10 of the Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.~~

~~**Phase Time Overcurrent Relay – Voltage Controlled (51V-C)**~~

~~Phase time overcurrent voltage-controlled relays (51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See section 3.10 of the~~See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional ~~time~~ overcurrent relays is similar. Note that the ~~Table 1setting~~setting criteria established within the Table 1 options ~~differ~~differs from ~~section 3.9.2~~ of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator ~~operates~~is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-~~1~~2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

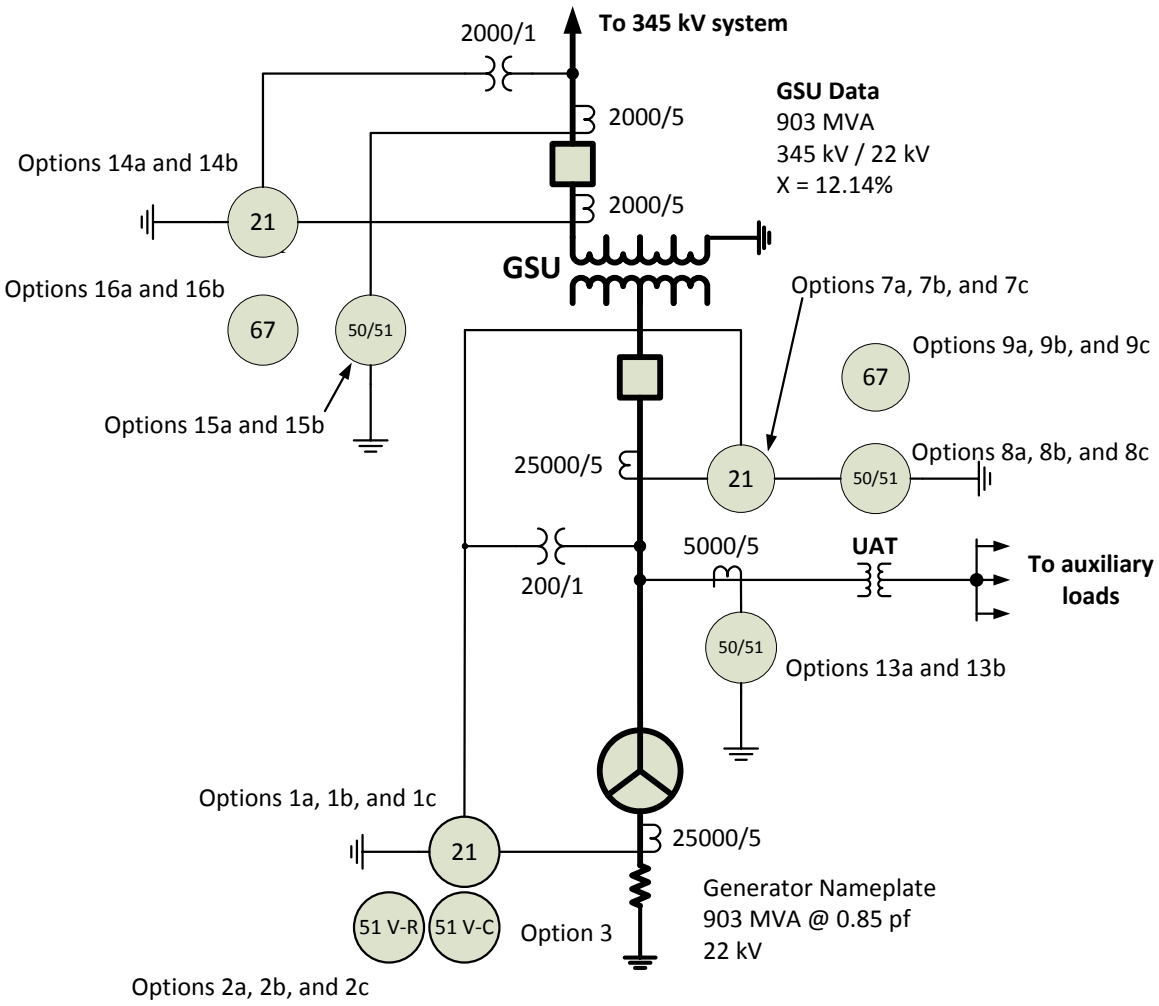


Figure 4. Relay Connection for corresponding synchronous options.

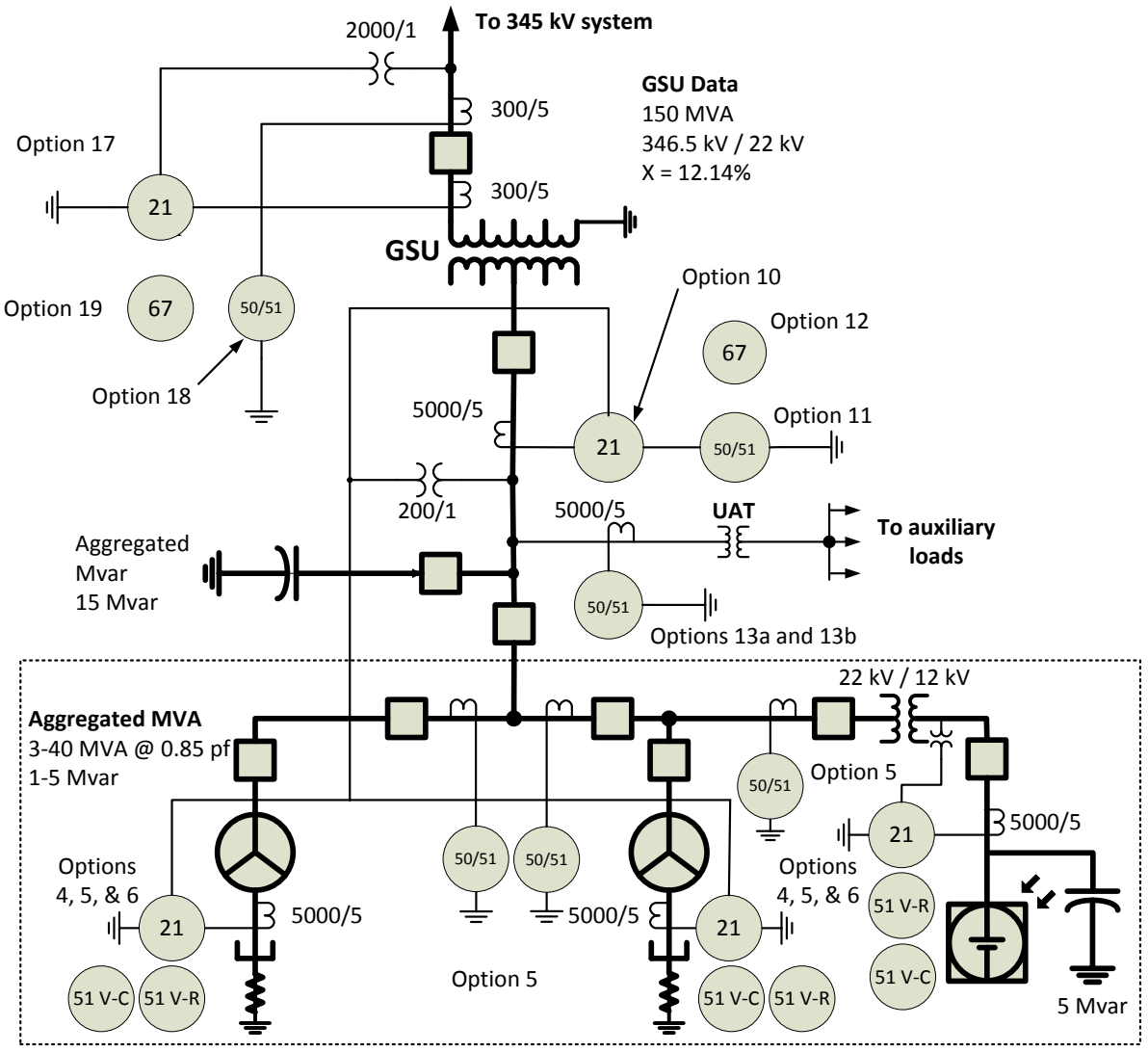


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~

calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts for~~as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~ in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element ~~is~~shall be set less than the calculated impedance derived from ~~115percent~~115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage~~-~~ Restrained ~~(51V-R~~) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase ~~time~~ overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which ~~change their~~changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer

is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer ~~and accounts~~as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element ~~is~~shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators;~~

~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 4, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase ~~Time~~ Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage~~-~~ Restrained ~~(51V-R) (Option 5)~~ (Options 5a and 5b))

Table 1, Option ~~5~~5a is provided for assessing loadability for asynchronous generators applying phase ~~time~~ overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which ~~change their~~changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option ~~5~~5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer

~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option ~~5~~5a, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The overcurrent element shall be set to not infringe upon the resource capability with worst case documented tolerances applied to the setting. Figure A illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in ~~section 3.10~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting ~~is~~shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability ~~for GSU transformers applying~~of phase distance relays that are directional toward the Transmission system ~~on synchronous generators that are~~and connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~overcurrent~~impedance element ~~overall~~than Options 7a or 7b.

For Options 7a and 7b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate

generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 7c, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability for GSU transformers applying phase time overcurrent relays on synchronous generators that are connected to the generator side of the GSU transformer of a synchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 15.~~

~~Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying a 0.95 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is the simplest calculation that approximates the stressed system conditions.~~

~~Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer and accounts for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more involved, more precise setting of the impedance element than Option 8a.~~

~~Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.~~

~~For Options 8a and 8b, the overcurrent element is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW~~

~~capability reported to the Transmission Planner, and Reactive Power output that equates to 150 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor.~~

~~For Option 8c, the overcurrent element~~ ~~is set greater than 115 percent of the calculated current derived from: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.~~

~~Generator Step-up Transformer (Synchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Options 9a, 9b and 9c)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ ~~Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document.~~ Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability ~~for GSU transformers applying~~of phase directional ~~time~~ overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is the simplest~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on ~~a~~the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~and accounts for~~, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more ~~involved, more~~in-depth and precise method for setting ~~of~~ the ~~impedance~~overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more

~~involved, more~~in-depth and precise method for setting ~~of~~ the overcurrent element ~~overall~~than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value~~,~~ (derived from the generator nameplate MVA rating at rated power factor~~.~~).

For Option 9c, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. ~~Where~~For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

~~Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element ~~is~~shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. ~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform ~~setting~~loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability ~~for GSU transformers applying~~of phase ~~time~~ overcurrent relays ~~on asynchronous generators~~ that are connected to the generator-side of the GSU transformer~~. Where~~ of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying ~~a~~the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer ~~times~~, by the GSU transformer turns ratio (excluding the impedance). This ~~is a simple~~ calculation ~~that approximates~~is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant.~~

~~Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~

For Option 11, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined

by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

~~Generator Step-up Transformer (Asynchronous Generators) Phase Directional Time Overcurrent Relay – Directional Toward Transmission System (67) (Option 12)~~

~~The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers.~~ ~~Note that the setting criteria established within these options differ from section 3.9.2 of the Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.~~

~~Table 1, Option 12 is provided for assessing loadability for GSU transformers applying phase directional time overcurrent relays directional toward the Transmission System on asynchronous generators that are connected to the generator-side of the GSU transformer of an asynchronous generator. Where the relay is connected on the high-side of the GSU transformer, use Option 19.~~
~~Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer.~~ ~~The generator bus voltage is calculated by multiplying a 1.0 per unit nominal voltage at the high-side terminals of the GSU transformer times the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.~~
~~Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage.~~ ~~Asynchronous generators do not produce as much Reactive Power as synchronous generators;~~ ~~the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.~~
~~For Option 12, the overcurrent element is set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices.~~ ~~This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.~~

Unit Auxiliary Transformers Phase ~~Time~~ Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase ~~time~~ overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase ~~time~~ overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard.

Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase ~~time~~ overcurrent relaying applied ~~to~~at the low-side of the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

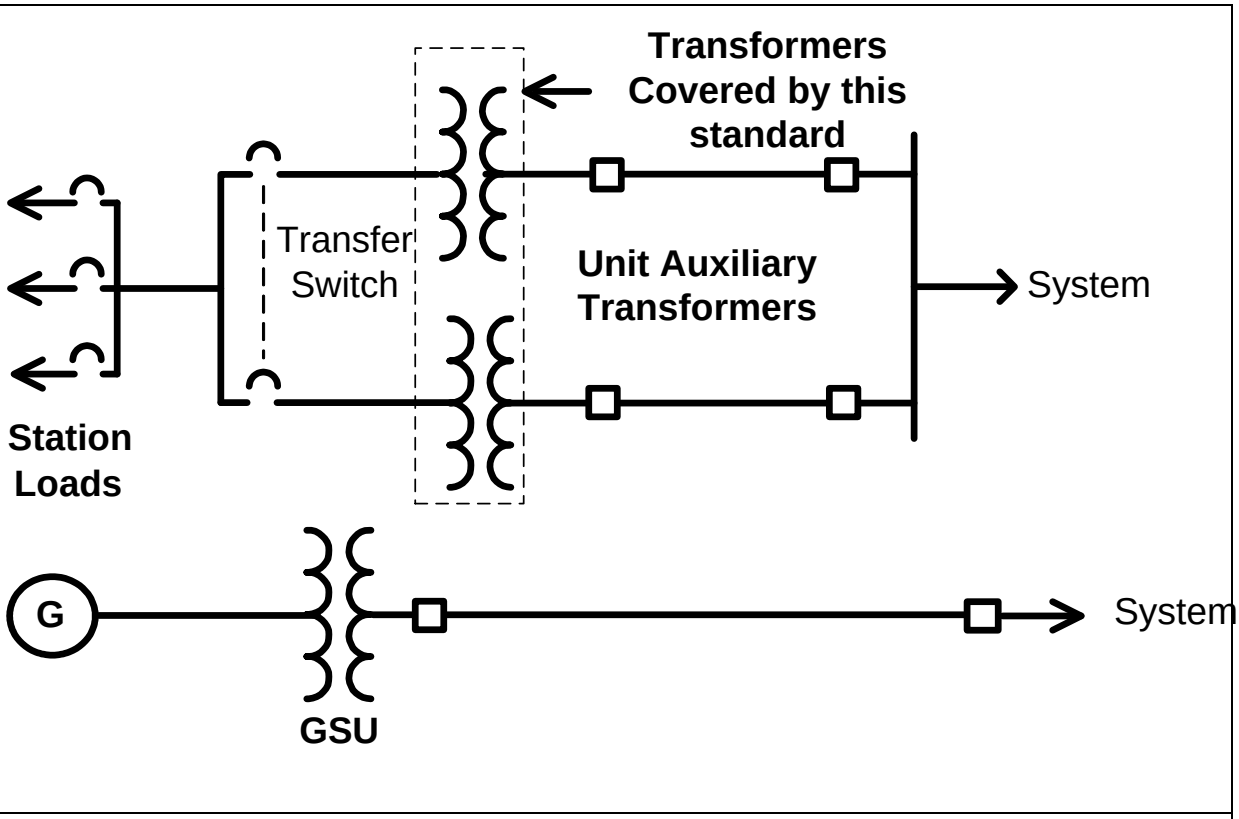


Figure-6 – Auxiliary Power System (independent from generator).

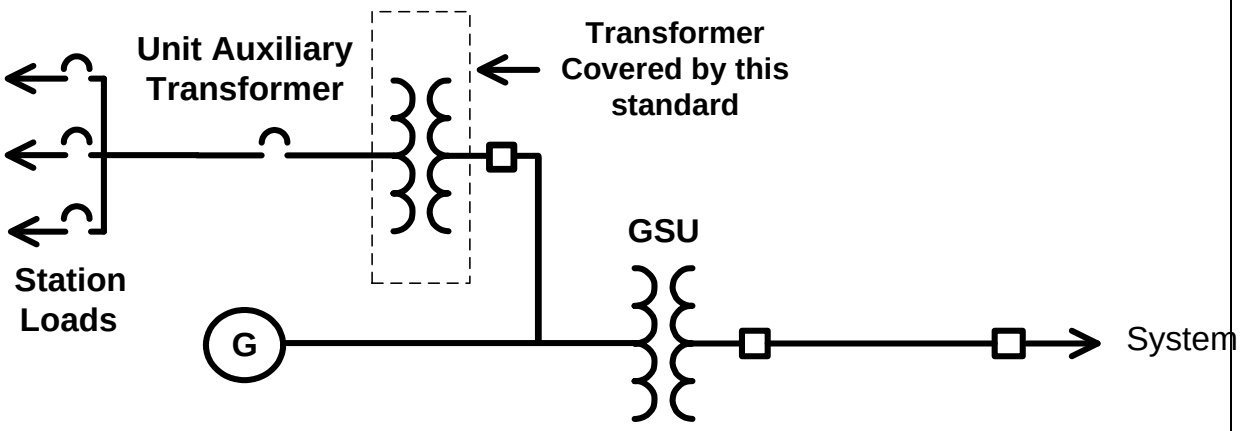


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase ~~time~~ overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting ~~pickup~~ compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response

of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum ~~pickup~~setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy

directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element ~~is~~shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase

instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional ~~time~~ overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit ~~Transmission system~~of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit ~~nominal voltage on the high side terminals of the GSU transformer prior to field forcing.~~line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other ~~application~~applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element ~~is~~shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ These margins are based on guidance found in ~~section 3.1~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the impedance from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 17, the impedance element ~~is~~shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase ~~Time~~ Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase ~~time~~ overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals~~location of the ~~GSU transformer~~relay to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 18, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional ~~Time~~ Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. ~~Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.~~ Note that the setting criteria established within ~~these~~the Table 1 options ~~differ~~differs from ~~section 3.9.~~Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional ~~time~~ overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from ~~operating~~tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage ~~on~~at the ~~high-side terminals of the GSU transformer~~relay location to calculate the current from the maximum aggregate nameplate MVA~~. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant~~.

For Option 19, the overcurrent element ~~is~~shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio_hv} = \frac{2000}{5}$

Example Calculations.	
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$
Reactive Power output of static reactive device generation:	$MVAR_{gen_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch_ratio_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio_remote_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (2) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (4) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (5) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7° \, \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.035\angle 58.7° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 6.9873\angle 58.7° \, \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{0.896}$$

$$Z_{max} < 7.793\angle 85.0° \, \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times |V_{high-side}|)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{~~7.74\ \Omega~~}{~~\cos(85.0° - 58.7°)~~} \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633 \angle 85.0° \ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

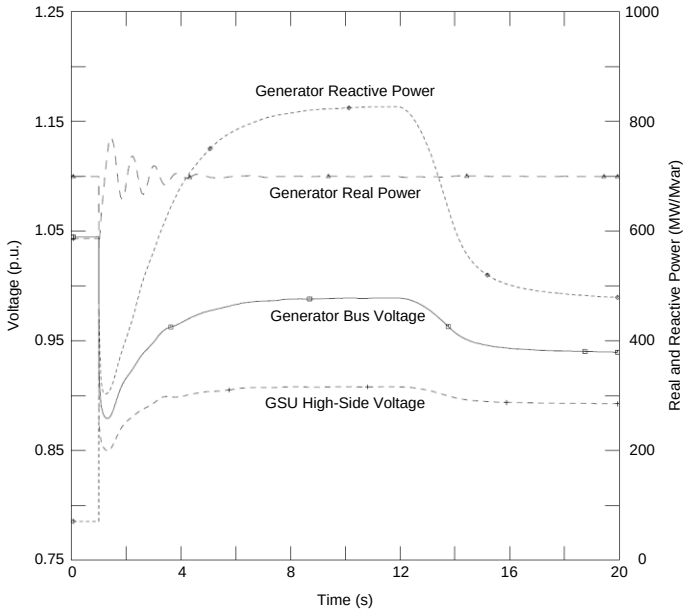
$$Q = 827.4\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$

Example Calculations: Options 1c and 7c



Apparent power (S):

Eq. (24) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{\cancel{V_{bus}^2}}{\cancel{S^*}} \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

Example Calculations: Options 1c and 7c

$$Z_{sec} = 0.437\angle 49.8° \, \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8° \, \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{10.92\angle 49.8° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 9.50\angle 49.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{\text{~~9.50 Ω~~}}{\text{~~cos(85.0° − 49.8°)~~}} \frac{9.50\ \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50\ \Omega}{0.8171}$$

$$Z_{max} < \ 11.63\angle 85.0° \, \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (29) $$P = \ GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \ \times 0.85$$

$$P = 767.6\ MW$$

Example Calculations: Option 2a

Reactive Power output (Q):

Eq. (30) $Q = 150\% \times P$

$Q = 1.50 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$

$V_{gen} = 20.81\ kV$

Apparent power (S):

Eq. (32) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (33) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$

$I_{pri} = 37383\ A$

Secondary current (I_{sec}):

Eq. (34) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$

Example Calculations: Option 2a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Example Calculations: Option 2b

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Option 2b

Apparent power (S):

Eq. (46) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (47) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$

$I_{pri} = 35553\ A$

Secondary current (I_{sec}):

Eq. (48) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$

$I_{sec} = 7.111\ A$

To satisfy the 115% margin in Option 2b:

Eq. (49) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$

$I_{\mathrm{sec}\,limit} > 8.178\ A$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~voltage restrained~~ relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.~~

In this simulation the following values are derived:

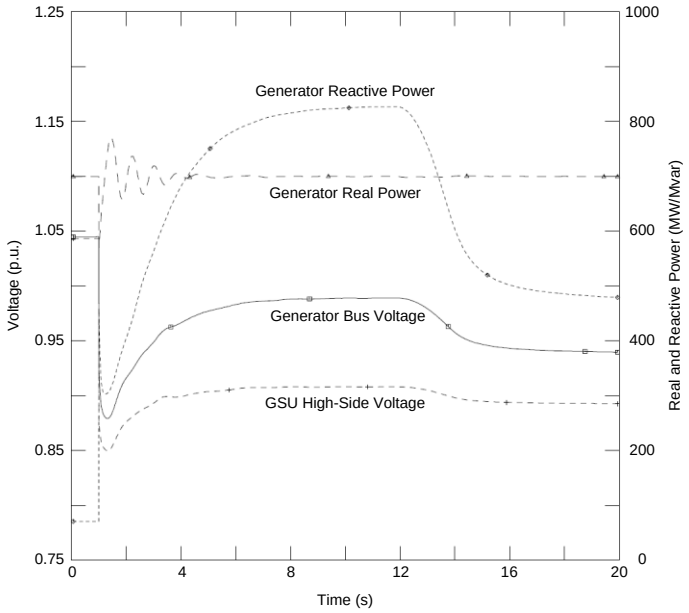
$$Q = 827.4\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$

Example Calculations: Option 2c



Apparent power (S):

Eq. (50) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j827.4\ Mvar$

$S = 1083.8 \angle 49.8°\ MVA$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \frac{~~S~~}{~~\sqrt{3} \times V_{bus}~~} \frac{S}{\sqrt{3} \times V_{bus_simulated}}$

$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$

$I_{pri} = 28790\ A$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$

Example Calculations: Option 2c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Option 2c:

Eq. (53) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.758\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.622\ A$$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C)~~ voltage controlled~~ relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21)— directional toward the Transmission system.

Example Calculations: Option 4

Real Power output (P):

Eq. (56) $$P = GEN_{Asych_nameplate} \times pf$$

$$P = 40\ MVA \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0 \angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0 \angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99 \angle 31.8°\ \Omega$$

Example Calculations: Option 4

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99 \angle 31.8° \, \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99 \angle 31.8° \, \Omega \times 5$$

$$Z_{sec} = 59.95 \angle 31.8° \, \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{59.95 \angle 31.8° \, \Omega}{1.30}$$

$$Z_{\text{sec}\,limit} = 46.12 \angle 31.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~,85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12 \, \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12 \, \Omega}{0.599}$$

$$Z_{max} < 77.0 \angle 85.0° \, \Omega$$

Example Calculations: Option ~~5~~5a

This represents the calculation for three asynchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 51V-R) ~~– voltage-restrained~~ relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option ~~5~~5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

Example Calculations: Option ~~5~~5a

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option ~~5~~5a:

Eq. (70) $$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.52\angle -39.2°\ A$$

Example Calculations: ~~Options 7a and 10~~Option 5b

~~This~~Similarly to Option 5a, this example represents the calculation for ~~a mixture of~~three asynchronous ~~(i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations)~~generators applying a phase ~~distance~~overcurrent (e.g., 50, 51, or 51V-R) relay ~~(21) – directional toward the Transmission system.~~. In this application it was assumed that 20 Mvar of total static compensation was added.

~~**Synchronous Generation (Option 7a)**~~

Real Power output (~~P_{sync}~~):P):

Eq. (71) ~~$P_{Synch} = GEN_{Synch_nameplate} \times pf$~~$P = 3 \times GEN_{Asynch_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Example Calculations: ~~Options 7a and 10~~Option 5b

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

Example Calculations: ~~Options 7a and 10~~Option 5b

$$I_{sec} = 3.473\angle -39.2° \; A$$

To satisfy Option 5b, the overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903 \; MVA \times 0.85$$

$$P_{Synch} = 767.6 \; MW$$

Reactive Power output (Q_{synch}):

Eq. (~~72~~78) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6 \; MW$$

$$Q_{Synch} = 1151.3 \; MW$$

Apparent power (S_{Synch}):

Eq. (~~73~~79) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0 \; MW + j1151.3 \; Mvar$$

Example Calculations: Options 7a and 10

Asynchronous Generation (Option 10)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~74~~80) $P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~75~~81) $Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (~~76~~82) $S_{Asynch} = P_{Asynch} + jQ_{Asynch}$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (~~77~~83) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (~~78~~84) $S = 115\% \times \left(P_{Synch_reported} + jQ_{Synch}\right) + 130\% \times (P_{Asynch} + jQ_{Asynch})$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

Example Calculations: Options 7a and 10

$$S = 1711.8 \angle 56.8° \, MVA$$

Primary impedance (Z_{pri}):

Eq. (~~79~~85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81 \, kV)^2}{1711.8 \angle -56.8° \, MVA}$$

$$Z_{pri} = 0.2527 \angle 56.8° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~80~~86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527 \angle 56.8° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527 \angle 56.8° \, \Omega \times 25$$

$$Z_{sec} = 6.32 \angle 56.8° \, \Omega$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~85~~84 to satisfy the margin requirements in Options 7a and 10~~:~~.

Eq. (~~81~~87) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\text{sec}\,limit} = \frac{6.32 \angle 56.8° \, \Omega}{1.00}$$

$$Z_{\text{sec}\,limit} = 6.32 \angle 56.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°,~~85°, then the maximum allowable impedance reach is:

Eq. (~~82~~88) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

Example Calculations: Options 7a and 10

$$Z_{max} < \frac{6.32\ \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32\ \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0°\ \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (~~83~~89) $P = GEN_{Synch_nameplate} \times pf$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~84~~90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (~~85~~91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a and 9a

Apparent power (S):

Eq. (~~86~~92) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (~~87~~93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$

$I_{pri} = 37383\ A$

Secondary current (I_{sec}):

Eq. (~~88~~94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$

$I_{sec} = 7.477\ A$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (~~89~~95) $I_{\text{sec}\,limit} > I_{sec} \times 115\%$

$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$

$I_{\text{sec}\,limit} > 8.598\ A$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more ~~complex~~precise calculation for synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an “aggregate” value to illustrate the option:

Example Calculations: Options 8b and 9b

Real Power output (P):

Eq. (~~90~~96) $P = GEN_{Synch_nameplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (~~91~~97) $Q = 150\% \times P$

$Q = 1.50 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (~~92~~98) $P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$

$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$

$P_{pu} = 0.91\ p.u.$

Reactive Power output (Q):

Eq. (~~93~~99) $Q_{pu} = \frac{Q}{MVA_{base}}$

$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$

$Q_{pu} = 1.5\ p.u.$

Transformer impedance:

Eq. (~~94~~100) $X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$

Example Calculations: Options 8b and 9b

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (~~95~~101)
$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (~~97~~103)
$$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Example Calculations: Options 8b and 9b

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (~~99~~105)
$$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (~~100~~106)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4 \angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (~~101~~107)
$$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$$

$$I_{pri} = 35553\ A$$

Example Calculations: Options 8b and 9b

Secondary current (I_{sec}):

Eq. (~~102~~108)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.111\ A$$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (~~103~~109)
$$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.111\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.178\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase ~~time~~ overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

~~Real Power output (P_{Synch}):~~

Real Power output (P_{Synch}):

Eq. (~~104~~110)
$$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 8a, 9a, 11, and 12

Reactive Power output (Q_{Synch}):

Eq. (~~105~~111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (~~106~~112) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4 \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (~~107~~113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Primary current ($I_{pri\text{-}sync}$):

Eq. (~~108~~114) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7°\ MVA)}{1.73 \times 20.81\ kV}$$

$$I_{pri-sync} = 43061 \angle -58.7°\ A$$

Example Calculations: Options 8a, 9a, 11, and 12

Asynchronous Generation (Options 11 and 12)

~~Real Power output (P_{Asynch}):~~

Real Power output (P_{Asynch}):

Eq. (~~109~~115)
$$P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (~~110~~116)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (~~111~~117)
$$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S_{Asynch}):

Eq. (~~112~~118)
$$S_{Asynch} = 130\% \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S_{Asynch} = 171.1 \angle 39.2°\ MVA$$

Example Calculations: Options 8a, 9a, 11, and 12

Primary current ($I_{pri\text{-}async}$):

Eq. (~~113~~119)
$$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2° \, MVA}{1.73 \times 20.81 \, kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \, A$$

Secondary current (I_{sec}):

Eq. (~~114~~120)
$$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \, A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \, A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \, A$$

No additional margin is needed~~; therefore, the margin is 100%~~ because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation ~~94~~114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation ~~98:~~118.

Eq. (~~115~~121)
$$I_{\text{sec}\,limit} > I_{sec} \times 100\%$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \, A \times 1.00$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \, A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase ~~time~~ overcurrent relay~~.~~ (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter

Example Calculations: Options 8c and 9c

reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

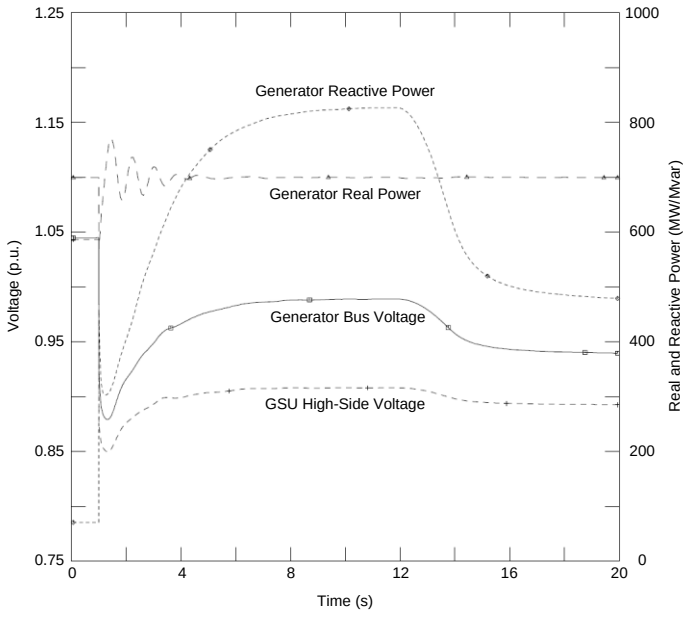
In this simulation the following values are derived:~~The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low side of the GSU transformer during field forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

$$Q = 827.4\ Mvar$$

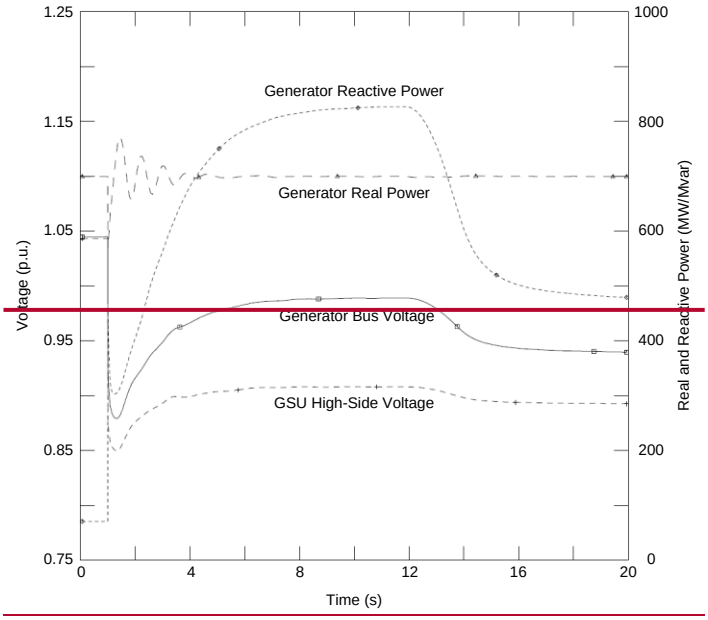
$$~~V_{bus}~~V_{bus_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Example Calculations: Options 8c and 9c



Apparent power (S):

Eq. (~~116~~122) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Primary current (I_{pri}):

Eq. (~~117~~123) $I_{pri} = \frac{~~S~~}{~~\sqrt{3} \times V_{bus}~~} \frac{S}{\sqrt{3} \times V_{bus_simulated}}$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (~~118~~124) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

Example Calculations: Options 8c and 9c

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (~~119~~125) $I_{\text{sec } limit} > I_{sec} \times 115\%$

$$I_{\text{sec } limit} > 5.758\ A \times 1.15$$

$$I_{\text{sec } limit} > 6.622\ A$$

Example Calculations: Option10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21)— directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~120~~126) $P = 3 \times GEN_{Asych_nameplate} \times pf$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~121~~127) $Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~122~~128) $V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$

Example Calculations: Option10

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~123~~129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~124~~130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~125~~131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644\ \angle 39.2°\ \Omega \times 5$$

$$Z_{sec} = 18.22\ \angle 39.2°\ \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (~~126~~132) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{18.22\angle 39.2°\ \Omega}{1.30}$$

Example Calculations: Option10

$$Z_{\sec limit} = 14.02\angle 39.2° \ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~127~~133)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{14.02\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02\ \Omega}{0.6972}$$

$$Z_{max} < 20.11\angle 85.0° \ \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase ~~time~~ overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional ~~time~~ overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~128~~134)
$$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~129~~135)
$$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

Example Calculations: Options 11 and 12

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (~~130~~136)
$$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (~~131~~137)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6 \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~132~~138)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (~~133~~139)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473 \angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473 \angle -39.2°\ A$$

Example Calculations: Options 11 and 12

To satisfy the 130% margin in Options 11 and12:

Eq. (~~134~~140)
$$I_{\sec limit} > I_{sec} \times 130\%$$

$$I_{\sec limit} > 3.473\angle -39.2° \; A \times 1.30$$

$$I_{\sec limit} > 4.515\angle -39.2° \; A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes ~~that~~ the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (~~135~~141)
$$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60 \; MVA}{1.73 \times 13.8 \; kV}$$

$$I_{pri} = 2510.2 \; A$$

Secondary current (I_{sec}):

Eq. (~~136~~142)
$$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

$$I_{sec} = \frac{2510.2 \; A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51 \text{ A}$$

To satisfy the 150% margin in Options 13a:

Eq. (~~137~~143)
$$I_{\sec limit} > I_{sec} \times 150\%$$

Example Calculations: Options 13a and 13b

$$I_{sec\,limit} > 2.51\ A \times 1.50$$

$$I_{sec\,limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~138~~144)
$$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~139~~145)
$$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high side~~line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (~~140~~146)
$$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Example Calculations: Option 14a

Apparent power (S):

Eq. (~~141~~147) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (~~142~~148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~143~~149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (~~144~~150) $$Z_{\sec limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\sec limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

$$Z_{\sec limit} = 12.928\angle 52.77°\ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Example Calculations: Option 14a

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~145~~151)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < 15.283 \angle 85.0°\ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that~~connected to synchronous generation. In this example, the Element is ~~applying~~protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.~~

In this simulation the following values are derived:

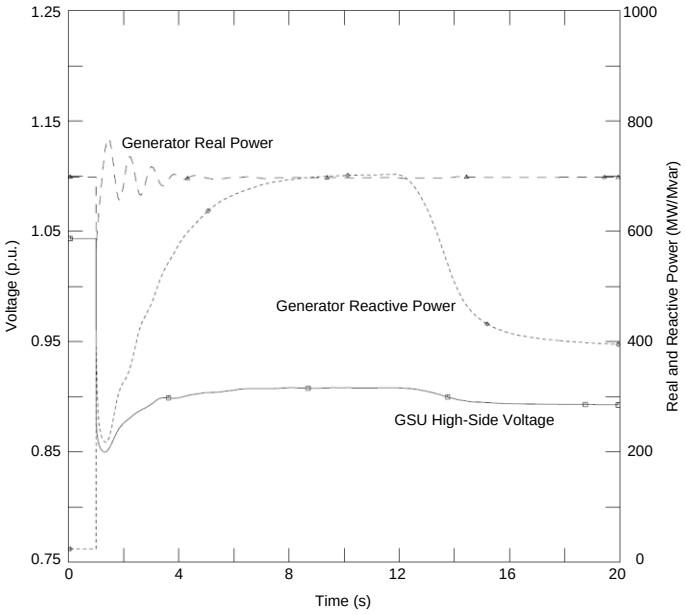
$$Q = 703.6\ Mvar$$

Example Calculations: Option 14b

$$~~V_{bus}~~V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (~~146~~152)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (~~147~~153)
$$Z_{pri} = \frac{~~\frac{V_{bus}^2}{S^*}~~}{} \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

Example Calculations: Option 14b

$$Z_{pri} = 98.90\angle 45.1° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~148~~154)
$$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1° \, \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (~~149~~155)
$$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{19.78\angle 45.1° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 17.20\angle 45.1° \, \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, then the maximum allowable impedance reach is:

Eq. (~~150~~156)
$$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{17.20 \, \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20 \, \Omega}{0.767}$$

$$Z_{max} < 22.42\angle 85.0° \, \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation. Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —installed on the high-side of the GSU transformer~~,~~ and remote end of the line. Option 16a represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —directional toward the Transmission system– installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line.

~~This example uses Option 15a as an example, where PTs and CTs are located in the high-side of the GSU transformer.~~Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer. The 0.85 per unit of the line nominal voltage at the relay location will be at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (~~151~~157)
$$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (~~152~~158)
$$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Example Calculations: Options 15a and 16a

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the ~~high side~~line nominal voltage:

Eq. (~~153~~159)
$$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (~~154~~160)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157 \angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (~~155~~161)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157 \angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6 \angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (~~156~~162)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

$$I_{sec} = \frac{2280.6 \angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and ~~15b~~16a:

Eq. (~~157~~163)
$$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

Example Calculations: Options 15a and 16a

$$I_{sec\,limit} > 5.701 \angle -52.8° \; A \times 1.15$$

$$I_{sec\,limit} > 6.56 \angle -52.8° \; A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903 \; MVA \times 0.85$$

$$P = 767.6 \; MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6 \; MW$$

$$Q = 921.12 \; Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus_remote_substation} = 0.85 \; p.u. \times V_{nom}$$

$$V_{bus_remote_substation} = 0.85 \times 345 \; kV$$

$$V_{bus_remote_substation} = 293.25 \; kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0 \; MW + j921.12 \; Mvar$$

$$S = 1157 \angle 52.8° \; MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus_remote_substation}}$$

Example Calculations: Options 15a and 16a

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio_remote_bus}}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.701 \angle -52.8°\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.56 \angle -52.8°\ A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for ~~a synchronous generation~~ Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant~~.~~ connected to synchronous generation. Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or ~~Phase~~phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —installed on the high-side of the GSU transformer~~.~~ and remote end of the line. Option 16b represents applying a phase directional ~~time overcurrent relay or Phase directional~~instantaneous overcurrent supervisory ~~elements (~~element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications —directional toward the Transmission system– installed on the high-side of the GSU and at the remote end of the line and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU and remote end of the line.

~~This example uses Option 15b as a simulation example~~Example calculations are provided for the case, where PTs and CTs are located at the remote end of the line from the plant. The 0.85 per unit of the line nominal voltage is applied at the remote end of the line.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the ~~in the~~ high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

~~The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.~~

In this simulation the following values are derived:

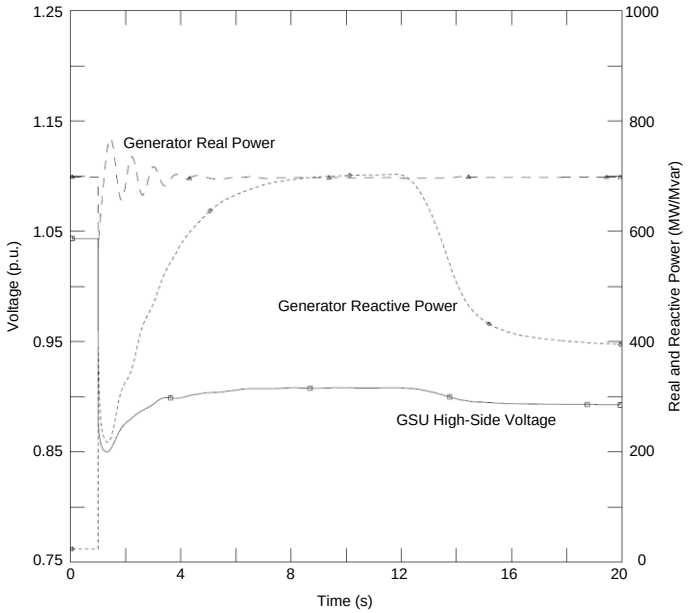
$$Q = 703.6\ Mvar$$

$$~~V_{bus}~~V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$

Example Calculations: Options 15b and 16b



Apparent power (S):

Eq. (~~158~~171)
$$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (~~159~~172)
$$I_{pri} = \frac{\cancel{S^*}}{\cancel{\sqrt{3} \times V_{bus}}} \frac{S^*}{\sqrt{3} \times V_{bus_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

$$I_{pri} = 1831.2\angle -45.1°\ A$$

Secondary current (I_{sec}):

Eq. (~~160~~173)
$$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

Example Calculations: Options 15b and 16b

$$I_{sec} = \frac{1831.2\angle -45.1° \; A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578 \angle -45.1° \; A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (~~161~~174)
$$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 4.578 \angle -45.1° \; A \times 1.15$$

$$I_{\text{sec}\,limit} > 5.265 \angle -45.1° \; A$$

Example Calculations: Option 17

Option 17 represents the calculation for ~~three asynchronous generation~~ Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21)~~–~~ directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (~~162~~175)
$$P_{Asynch} = \; 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \; MVA \; \times 0.85$$

$$P_{Asynch} = 102.0 \; MW$$

Reactive Power output (Q):

Eq. (~~163~~176)
$$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \; Mvar$$

Example Calculations: Option 17

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high side~~line nominal voltage for the bus voltage (V_{bus}):

Eq. (~~164~~177)
$$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (~~165~~178)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (~~166~~179)
$$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (~~167~~180)
$$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (~~168~~181)
$$Z_{\sec limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\sec limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\sec limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at ~~85°~~85°, and then the maximum allowable impedance reach is:

Eq. (~~169~~182)
$$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for ~~three generation~~relays on Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~that is~~. Option 18 represents applying a phase time overcurrent (e.g., 51) ~~relay connected to three asynchronous generators.~~ and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional ~~time~~ overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer and remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 18 and 19

Real Power output (P):

Eq. (~~170~~183)
$$P = 3 \times GEN_{Asych_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (~~171~~184)
$$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the ~~high side~~line nominal voltage (V_{bus}):

Eq. (~~172~~185)
$$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (~~173~~186)
$$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (~~174~~187)
$$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

Example Calculations: Options 18 and 19

$$I_{pri} = 220.5 \angle -39.2° A$$

Secondary current (I_{sec}):

Eq. (~~175~~188)
$$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio_hv}}$$

$$I_{sec} = \frac{220.5 \angle -39.2° \, A}{\frac{300}{5}}$$

$$I_{sec} = 3.675 \angle -39.2° \, A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (~~176~~189)
$$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.675 \angle -39.2° \, A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.778 \angle -39.2° \, A$$

End of calculations

Rationale:

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1:

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

The standard drafting team (PRC_025) is posting Draft 1 of PRC-025-2, Generator Relay Loadability for a 45-day formal comment period and initial ballot in the last ten days of the comment period.

Completed Actions	Date
The Standards Committee (SC) authorized the SAR for posting	September 14, 2016
Draft 1 of the Standards Authorization Request (SAR) was posted for a 30-day formal comment period	September 16, 2016 through October 18, 2016
Draft 2 of the SAR was posted for a 15-day informal comment period	March 20, 2017 through April 3, 2017
The SC accepted the SAR and appointed the SAR drafting team as the standard drafting team (SDT)	April 19, 2017

Anticipated Actions	Date
45-day formal comment period with initial ballot	July 2017
45-day formal comment period with additional ballot	September 2017
10-day final ballot	January 2018
Board adoption	February 2018

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):
None.

A. Introduction

1. **Title:** **Generator Relay Loadability**

2. **Number:** **PRC-025-2**

3. **Purpose:** To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Generator Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.2. Transmission Owner that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.1.3. Distribution Provider that applies load-responsive protective relays at the terminals of the Elements listed in 3.2, Facilities.

   4.2. Facilities: The following Elements associated with Bulk Electric System (BES) generating units and generating plants, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:

   4.2.1. Generating unit(s).

   4.2.2. Generator step-up (i.e., GSU) transformer(s).

   4.2.3. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online.[1]

   4.2.4. Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.5. Elements utilized in the aggregation of dispersed power producing resources.

5. **Effective Date:** See Implementation Plan

6. **Background:** After analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have

[1] These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Loss of these transformers will result in removing the generator from service. Refer to the PRC-025-2 Guidelines and Technical Basis for more detailed information concerning unit auxiliary transformers.

tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This tripping has often been determined to have expanded the scope and/or extended the duration of that disturbance. This was noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent.[2]

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage may be widely depressed and may fluctuate. In order to support the system during this transient phase of a disturbance, this standard establishes criteria for setting load-responsive protective relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from the voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

7. Standard Only Definition: None.

B. Requirements and Measures

R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]*

M1. For each load-responsive protective relay, each Generator Owner, Transmission Owner, and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) that settings were applied in accordance with PRC-025-2 – Attachment 1: Relay Settings.

C. Compliance

8. Compliance Monitoring Process

8.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

[2] Interim Report: Causes of the August 14th Blackout in the United States and Canada, U.S.-Canada Power System Outage Task Force, November 2003 (http://www.nerc.com/docs/docs/blackout/814BlackoutReport.pdf)

8.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority (CEA) may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Distribution Provider shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner, Transmission Owner, and Distribution Provider shall retain evidence of Requirement R1 and Measure M1 for the most recent three calendar years.
- If a Generator Owner, Transmission Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

8.3. Compliance Monitoring and Assessment Processes

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

8.4. Additional Compliance Information

None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Long-Term Planning	High	N/A	N/A	N/A	The Generator Owner, Transmission Owner, and Distribution Provider did not apply settings in accordance with *PRC-025-2 – Attachment 1: Relay Settings*, on an applied load-responsive protective relay.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee, "Considerations for Power Plant and Transmission System Protection Coordination," technical reference document, Revision 2. (Date of Publication: July 2015)

IEEE C37.102-2006, "IEEE Guide for AC Generator Protection." (Date of Publication: 2006)

IEEE C37.17-2012, "IEEE Standard for Trip Systems for Low-Voltage (1000 V and below) AC and General Purpose (1500 V and below) DC Power Circuit Breakers." (Date of Publication: September 18, 2012)

IEEE C37.2-2008, "IEEE Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations." (Date of Publication: October 3, 2008)

Version History

Version	Date	Action	Change Tracking
1	August 15, 2013	Adopted by NERC Board of Trustees	New
1	July 17, 2014	FERC order issued approving PRC-025-1	
2	April 19, 2017	SAR accepted by Standards Committee	Revision
2		Adopted by NERC Board of Trustees	
2		FERC order issued approving PRC-025-2	

PRC-025-2 – Attachment 1: Relay Settings

Introduction

This standard does not require the Generator Owner, Transmission Owner, or Distribution Provider to use any of the protective functions listed in Table 1. Each Generator Owner, Transmission Owner, and Distribution Provider that applies load-responsive protective relays on their respective Elements listed in 3.2, Facilities, shall use one of the following Options in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Generators

Synchronous generator relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner, and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

Asynchronous generator relay setting criteria values (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner, including the Mvar output of any static or dynamic reactive power devices. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard as a minimum requirement. The Generator Owner may base settings on a capability that is higher than what is reported to the Transmission Planner.

For applications where synchronous and asynchronous generator types are combined on a generator step-up transformer or on Elements that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads), the setting criteria shall be determined by vector summing the setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Transformers

Calculations using the GSU transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with de-energized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU transformer turns ratio shall be used.

Applications that use more complex topology, such as generators connected to a multiple winding transformer, are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and may require simulation to avoid overly conservative

assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Multiple Lines

Applications that use more complex topology, such as multiple lines that connect the generator step-up (GSU) transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) are not directly addressed by the criteria in Table 1. These topologies can result in complex power flows, and it may require simulation to avoid overly conservative assumptions to simplify the calculations. Entities with these topologies should set their relays in such a way that they do not operate for the conditions being addressed in this standard.

Exclusions

The following protection systems are excluded from the requirements of this standard:

1. Any relay elements that are in service only during start up.
2. Load-responsive protective relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes).
3. Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard.
4. Protective relay elements that are only enabled when other protection elements fail (e.g., overcurrent elements that are only enabled during loss of potential conditions).
5. Protective relay elements used only for Remedial Action Schemes that are subject to one or more requirements in a NERC or Regional Reliability Standard.
6. Protection systems that detect generator overloads that are designed to coordinate with the generator short time capability by utilizing an extremely inverse characteristic set to operate no faster than 7 seconds at 218% of full load current (e.g., rated armature current), and prevent operation below 115% of full-load current.[3]
7. Protection systems that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions.

Table 1

Table 1 below is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., synchronous or asynchronous generators, generator step-up transformers, unit auxiliary transformers, Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly

[3] IEEE C37.102-2006, "Guide for AC Generator Protection," Section 4.1.1.2.

from a BES generating unit or generating plant). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive distance or overcurrent protective relay by IEEE device numbers (e.g., 21, 50, 51, 51V-C, 51V-R, or 67) according to the application in the first column. This also includes manufacture protective device trip unit designations for long-time delay, short-time delay, and instantaneous (e.g., L, S, and I). A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text, except when the same application continues on the next page of the table with a different relay type.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and setting criteria in the fourth and fifth column, respectively. The bus voltage column and setting criteria columns provide the criteria for determining an appropriate setting. The table is further formatted by shading groups of relays associated with asynchronous generator applications. Synchronous generator applications and the unit auxiliary transformer applications are not shaded. Also, intentional buffers were added to the table such that similar options, as possible, would be paired together on a per page basis. Note that some applications may have an additional pairing that might occur on adjacent pages.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[4] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Synchronous generating unit(s), including Elements utilized in the aggregation of dispersed power producing resources	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner, and (2) Reactive Power output – 150% of the MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the gross MW capability reported to the Transmission Planner or, and (2) Reactive Power output –100% of the maximum gross Mvar output during field-forcing as determined by simulation
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	3	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Asynchronous generating unit(s) (including inverter-based installations), including Elements utilized in the aggregation of dispersed power producing resources	Phase distance relay (e.g., 21) – directional toward the Transmission system	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50, 51, or 51V-R – voltage-restrained)	5a	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
		OR		
		5b	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).
	Phase time overcurrent relay (e.g., 51V-C) – voltage controlled (Enabled to operate as a function of voltage)	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	Voltage control setting shall be set less than 75% of the calculated generator bus voltage
A different application starts on the next page				

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer[5]	7a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		7c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] If the relay is installed on the high-side of the GSU transformer use Option 14.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer[6]	8a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		8c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[6] If the relay is installed on the high-side of the GSU transformer use Option 15.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to synchronous generators	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer[7]	9a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		9c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[7] If the relay is installed on the high-side of the GSU transformer use Option 16.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system – installed on generator-side of the GSU transformer[8]	10	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase overcurrent relay (e.g., 50 or 51) – installed on generator-side of the GSU transformer[9]	11	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional overcurrent relay (e.g., 67) – directional toward the Transmission system – installed on generator-side of the GSU transformer[10]	12	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application starts on the next page				

[8] If the relay is installed on the high-side of the GSU transformer use Option 17.
[9] If the relay is installed on the high-side of the GSU transformer use Option 18.
[10] If the relay is installed on the high-side of the GSU transformer use Option 19.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Unit auxiliary transformer(s) (UAT)	Phase overcurrent relay (e.g., 50 or 51) applied at the high-side terminals of the UAT, for which operation of the relay will cause the associated generator to trip.	13a	1.0 per unit of the winding nominal voltage of the unit auxiliary transformer	The overcurrent element shall be set greater than 150% of the calculated current derived from the unit auxiliary transformer maximum nameplate MVA rating
		OR		
		13b	Unit auxiliary transformer bus voltage corresponding to the measured current	The overcurrent element shall be set greater than 150% of the unit auxiliary transformer measured current at the generator maximum gross MW capability reported to the Transmission Planner
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to synchronous generators	Phase distance relay (e.g., 21) – directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of line[11]	14a	0.85 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		14b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[11] If the relay is installed on the generator-side of the GSU transformer use Option 7.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to synchronous generators	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line and/or phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer and remote end of the line[12]	15a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		15b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[12] If the relay is installed on the generator-side of the GSU transformer use Option 8.

Table 1. Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[4]	Setting Criteria
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant load.) – connected to synchronous generators	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line and/or phase directional time overcurrent relay (e.g., 67) – directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line[13]	16a	0.85 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor
		OR		
		16b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit of the line nominal voltage at the remote end of the line prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner, and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

[13] If the relay is installed on the generator-side of the GSU transformer use Option 9.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (e.g., 21) – directional toward the Transmission system– installed on the high-side of the GSU transformer and on the remote end of line[14]	17	1.0 per unit of the line nominal voltage at the relay location	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[14] If the relay is installed on the generator-side of the GSU transformer use Option 10.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase instantaneous overcurrent supervisory element (e.g., 50) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase time overcurrent relay (e.g., 51) – installed on the high-side of the GSU transformer and on the remote end of the line[15]	18	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

[15] If the relay is installed on the generator-side of the GSU transformer use Option 11.

Table 1. Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[4]**	**Setting Criteria**
Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Elements may also supply generating plant loads) – connected to asynchronous generators only (including inverter-based installations)	Phase directional instantaneous overcurrent supervisory element (e.g., 67) – associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU transformer and on the remote end of the line and/or Phase directional time overcurrent relay (e.g., 67) – installed on the high-side of the GSU transformer and on the remote end of the line[16]	19	1.0 per unit of the line nominal voltage at the relay location	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

[16] If the relay is installed on the generator-side of the GSU transformer use Option 12.

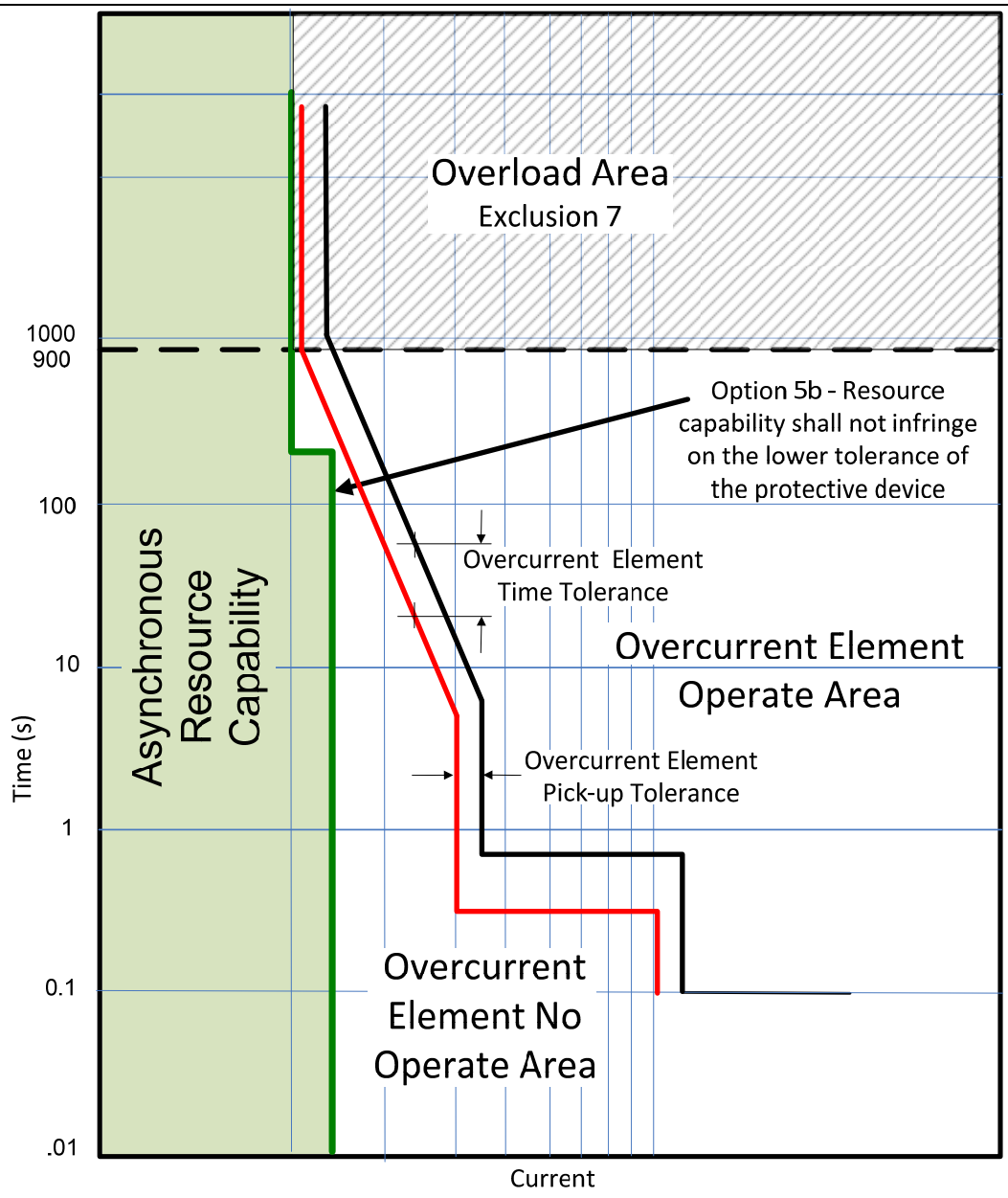


Figure A. This figure is for demonstration of Option 5b and does not mandate a specific type of protective curve or device manufacturer.

PRC-025-2 Guidelines and Technical Basis

Introduction

The document, "Considerations for Power Plant and Transmission System Protection Coordination," published by the NERC System Protection and Control Subcommittee (SPCS) provides extensive general discussion about the protective functions and generator performance addressed within this standard. This document was last revised in July 2015.[17]

The basis for the standard's loadability criteria for relays applied at the generator terminals or low-side of the generator step-up (GSU) transformer is the dynamic generating unit loading values observed during the August 14, 2003 blackout, other subsequent system events, and simulations of generating unit response to similar system conditions. The Reactive Power output observed during field-forcing in these events and simulations approaches a value equal to 150 percent of the Real Power (MW) capability of the generating unit when the generator is operating at its Real Power capability. In the SPCS technical reference document, two operating conditions were examined based on these events and simulations: (1) when the unit is operating at rated Real Power in MW with a level of Reactive Power output in Mvar which is equivalent to 150 percent times the rated MW value (representing some level of field-forcing) and (2) when the unit is operating at its declared low active Real Power operating limit (e.g., 40 percent of rated Real Power) with a level of Reactive Power output in Mvar which is equivalent to 175 percent times the rated MW value (representing some additional level of field-forcing).

Both conditions noted above are evaluated with the GSU transformer high-side voltage at 0.85 per unit. These load operating points are believed to be conservatively high levels of Reactive Power out of the generator with a 0.85 per unit high-side voltage which was based on these observations. However, for the purposes of this standard it was determined that the second load point (40 percent) offered no additional benefit and only increased the complexity for an entity to determine how to comply with the standard. Given the conservative nature of the criteria, which may not be achievable by all generating units, an alternate method is provided to determine the Reactive Power output by simulation. Also, to account for Reactive Power losses in the GSU transformer, a reduced level of output of 120 percent times the rated MW value is provided for relays applied at the high-side of the GSU transformer and on Elements that connect a GSU transformer to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant.

The phrase, "while maintaining reliable fault protection" in Requirement R1, describes that the Generator Owner, Transmission Owner, and Distribution Provider is to comply with this standard while achieving its desired protection goals. Load-responsive protective relays, as addressed within this standard, may be intended to provide a variety of backup protection functions, both within the generating unit or generating plant and on the Transmission system, and this standard is not intended to result in the loss of these protection functions. Instead, it is suggested that the

[17] http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Gen%20Prot%20Coordination%20Technical%20Reference%20Document.pdf

Generator Owner, Transmission Owner, and Distribution Provider consider both the requirement within this standard and its desired protection goals, and perform modifications to its protective relays or protection philosophies as necessary to achieve both.
For example, if the intended protection purpose is to provide backup protection for a failed Transmission breaker, it may not be possible to achieve this purpose while complying with this standard if a simple mho relay is being used. In this case, it may be possible to meet this purpose by replacing the legacy relay with a modern advanced-technology relay that can be set using functions such as load encroachment. It may otherwise be necessary to reconsider whether this is an appropriate method of achieving protection for the failed Transmission breaker, and whether this protection can be better provided by, for example, applying a breaker failure relay with a transfer trip system.

Requirement R1 establishes that the Generator Owner, Transmission Owner, and Distribution Provider must understand the applications of Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria ("Table 1") in determining the settings that it must apply to each of its load-responsive protective relays to prevent an unnecessary trip of its generator during the system conditions anticipated by this standard.

Applicability

To achieve the reliability objective of this standard it is necessary to include all load-responsive protective relays that are affected by increased generator output in response to system disturbances. This standard is therefore applicable to relays applied by the Generator Owner, Transmission Owner, and Distribution Provider at the terminals of the generator, GSU transformer, unit auxiliary transformer (UAT), Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, and Elements utilized in the aggregation of dispersed power producing resources.

The Generator Owner's interconnection facility (in some cases labeled a "transmission Facility" or "generator leads") consists of Elements between the GSU transformer and the interface with the portion of the Bulk Electric System (BES) where Transmission Owners take over the ownership. This standard does not use the industry recognized term "generator interconnection Facility" consistent with the work of Project 2010-07 (Generator Requirements at the Transmission Interface), because the term generator interconnection Facility implies ownership by the Generator Owner. Instead, this standard refers to these Facilities as "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" to include these Facilities when they are also owned by the Transmission Owner or Distribution Provider. The load-responsive protective relays in this standard for which an entity shall be in compliance is dependent on the location and the application of the protective functions. Figures 1, 2, and 3 illustrate various generator interface connections with the Transmission system.

Figure 1

Figure 1 is a single (or set) of generators connected to the Transmission system through a radial line that is used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 located on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relay R2 located on the incoming source breaker CB102 to the generating plant applies relaying that primarily protects the line by using line differential relaying from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 1 (i.e., CB102 and CB103) must be considered. If relay R2 or R3 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2 or R3 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

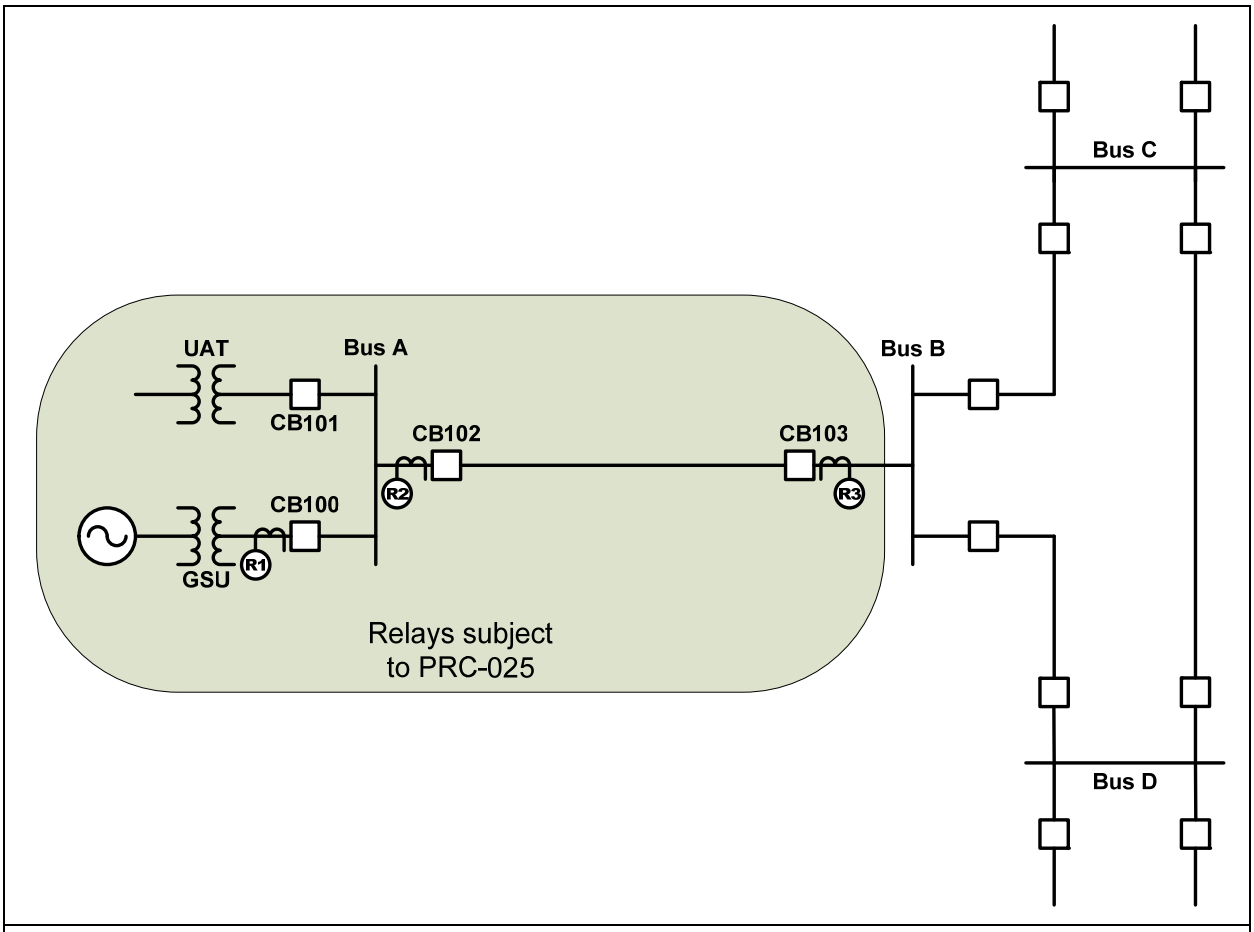


Figure 1. Generation exported through a single radial line.

Figure 2

Figure 2 is an example of a single (or set) of generators connected to the Transmission system through multiple lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus B. Under this application, relay R1 would apply the loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

The protective relays R2 and R3 located on the incoming source breakers CB102 and CB103 to the generating plant applies relaying that primarily protects the line from Bus A to B and also provides backup protection to the transmission relaying at Bus B. In this case, the relay function that provides line protection would apply the loadability requirement in PRC-025-2 and an appropriate option for the application from Table 1 (e.g., Options 15a, 15b, 16a, 16b, 18, and 19) for phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-

based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications. The backup protective function would apply the requirement in the PRC-025-2 standard using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are applicable to the standard, the loadability for relays applied on these Elements as shown in the shaded area of Figure 2 (i.e., CB102, CB103, CB104, and CB105) must be considered. If relay R2, R3, R4, or R5 is set with an element directional toward the transmission system (e.g., Buses B, C and D) or are non-directional, the relay would be affected by increased generator output in response to system disturbances and must meet the loadability setting criteria described in the standard. If relay R2, R3, R4, or R5 is set with an element directional toward the generator (e.g., Bus A), the relay would not be affected by increased generator output in response to system disturbances; therefore, the entity would not be required to apply the loadability setting criteria described in this standard.

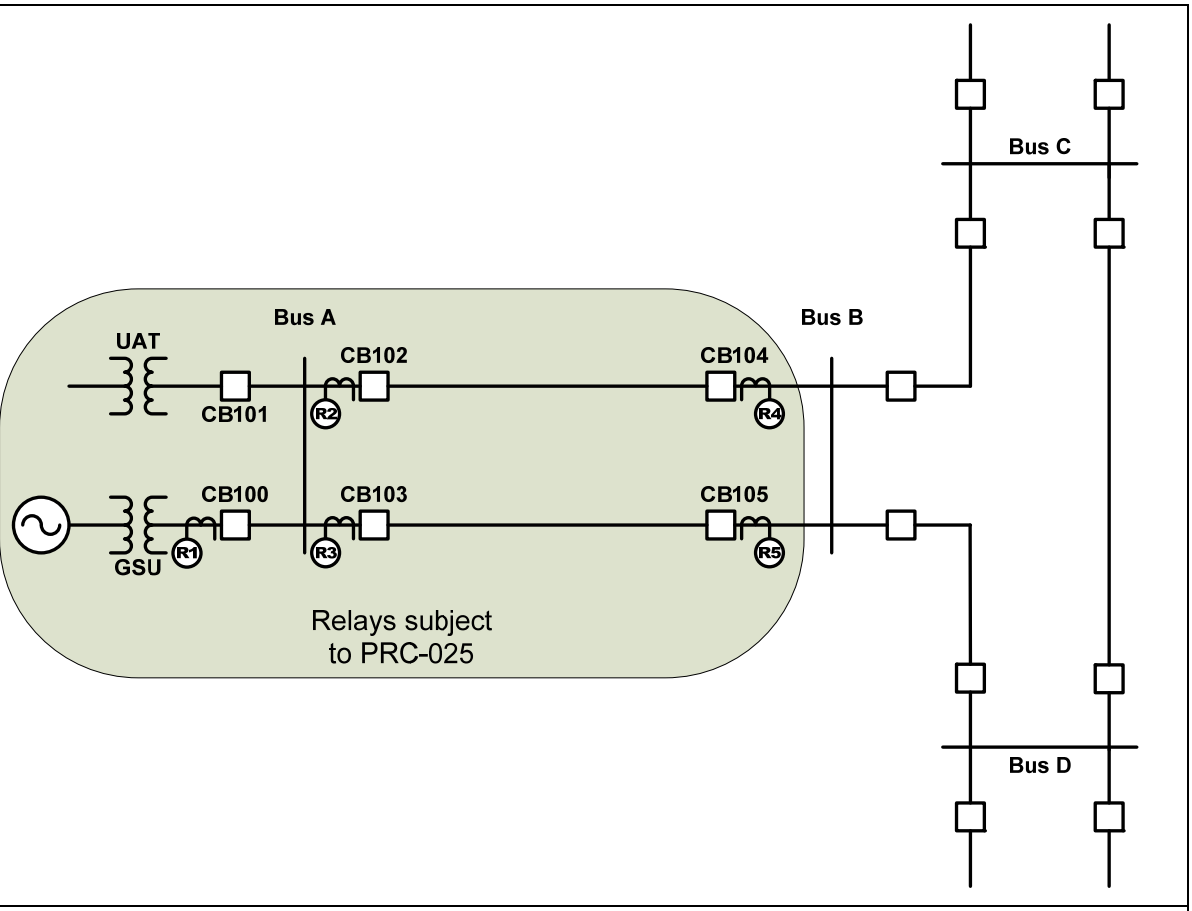


Figure 2. Generation exported through multiple radial lines.

Figure 3

Figure 3 is example a single (or set) of generators exporting power dispersed through multiple lines to the Transmission system through a network. The protective relay R1 on the high-side of the GSU transformer breaker CB100 is generally applied to provide backup protection to the Transmission relaying located at Bus A and in some cases Bus C or Bus D. Under this application, relay R1 would apply the applicable loadability requirement in PRC-025-2 using an appropriate option for the application from Table 1 (e.g., Options 14 through 19) for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant.

Since the lines from Bus A to Bus C and from Bus A to Bus D are part of the transmission network, these lines would not be considered as Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Therefore, the applicable responsible entity would be responsible for the load-responsive protective relays R2 and R3 under the PRC-023 standard. The applicable responsible entity's loadability relays R4 and R5 located on the breakers CB104 and CB105 at Bus C and D are also subject to the requirements of the PRC-023 standard.

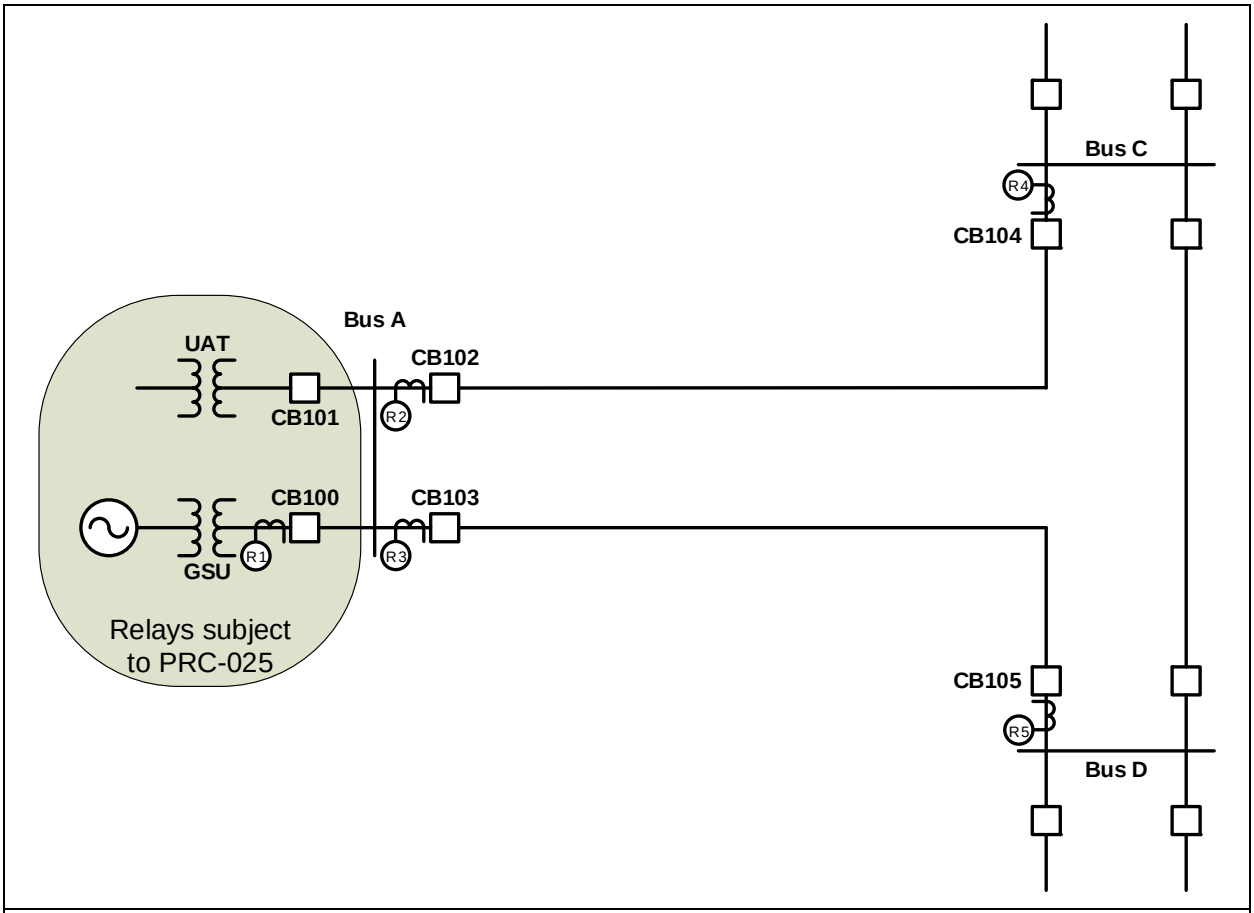


Figure 3. Generation exported through a network.

Elements utilized in the aggregation of dispersed power producing resources (in some cases referred to as a "collector system") consist of the Elements between individual generating units and the common point of interconnection to the Transmission system.

This standard is also applicable to the UATs that supply station service power to support the on-line operation of generating units or generating plants. These transformers are variably referred to as station power, unit auxiliary transformer(s), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running. Inclusion of these transformers satisfies a directive in FERC Order No. 733, paragraph 104, which directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT(s) that supply normal station service for a generating unit.

Synchronous Generator Performance

When a synchronous generator experiences a depressed voltage, the generator will respond by increasing its Reactive Power output to support the generator terminal voltage. This operating condition, known as "field-forcing," results in the Reactive Power output exceeding the steady-state capability of the generator and may result in operation of generation system load-responsive protective relays if they are not set to consider this operating condition. The ability of the generating unit to withstand the increased Reactive Power output during field-forcing is limited by the field winding thermal withstand capability. The excitation limiter will respond to begin reducing the level of field-forcing in as little as one second, but may take much longer, depending on the level of field-forcing given the characteristics and application of the excitation system. Since this time may be longer than the time-delay of the generator load-responsive protective relay, it is important to evaluate the loadability to prevent its operation for this condition.

The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage. The criteria established within Table 1 are based on 0.85 per unit of the line nominal voltage. This voltage was widely observed during the events of August 14, 2003, and was determined during the analysis of the events to represent a condition from which the System may have recovered, had other undesired behavior not occurred.

The dynamic load levels specified in Table 1 under column "Setting Criteria" are representative of the maximum expected apparent power during field-forcing with the Transmission system voltage at 0.85 per unit, for example, at the high-side of the GSU transformer. These values are based on records from the events leading to the August 14, 2003 blackout, other subsequent System events, and simulations of generating unit responses to similar conditions. Based on these observations, the specified criteria represent conservative but achievable levels of Reactive Power output of the generator with a 0.85 per unit high-side voltage at the point of interconnection.

The dynamic load levels were validated by simulating the response of synchronous generating units to depressed Transmission system voltages for 67 different generating units. The generating units selected for the simulations represented a broad range of generating unit and excitation system characteristics as well as a range of Transmission system interconnection characteristics. The simulations confirmed, for units operating at or near the maximum Real Power output, that it is possible to achieve a Reactive Power output of 1.5 times the rated Real Power output when the Transmission system voltage is depressed to 0.85 per unit. While the simulations demonstrated that all generating units may not be capable of this level of Reactive Power output, the simulations confirmed that approximately 20 percent of the units modeled in the simulations could achieve these levels. On the basis of these levels, Table 1, Options 1a (i.e., 0.95 per unit) and 1b (i.e., 0.85 per unit), for example, are based on relatively simple, but conservative calculations of the high-side nominal voltage. In recognition that not all units are capable of achieving this level of output Option 1c (i.e., simulation) was developed to allow the Generator Owner, Transmission Owner, or Distribution Provider to simulate the output of a generating unit when the simple calculation is not adequate to achieve the desired protective relay setting.

Dispersed Generation

This standard is applicable to dispersed generation such as wind farms and solar arrays. The intent of this standard is to ensure the aggregate facility as defined above will remain on-line during a system disturbance; therefore, all output load-responsive protective relays associated with the facility are included in PRC-025.

Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above are included in PRC-025-2. Load-responsive protective relays that are applied on Elements that connect these individual generating units through the point of interconnection with the Transmission system are within the scope of PRC-025-2. For example, feeder overcurrent relays and feeder step-up transformer overcurrent relays (see Figure 5) are included because these relays are challenged by generator loadability.

In the case of solar arrays where there are multiple voltages utilized in converting the solar panel DC output to a 60Hz AC waveform, the “terminal” is defined at the 60Hz AC output of the inverter-solar panel combination.

Asynchronous Generator Performance

Asynchronous generators will not respond to a disturbance with the same magnitude of apparent power that a synchronous generator will respond. Asynchronous generators, though, will support the system during a disturbance. Inverter-based generators will provide Real Power and Reactive Power (depending on the installed capability and regional grid code requirements) and may even provide a faster Reactive Power response than a synchronous generator. The magnitude of this response may slightly exceed the steady-state capability of the inverter but only for a short duration before limiter functions will activate. Although induction generators will not inherently supply Reactive Power, induction generator installations may include static and/or dynamic

reactive devices, depending on regional grid code requirements. These devices also may provide Real Power during a voltage disturbance. Thus, tripping asynchronous generators may exacerbate a disturbance.

Inverters, including wind turbines (i.e., Types 3 and 4) and photovoltaic solar, are commonly available with 0.90 power factor capability. This calculates to an apparent power magnitude of 1.11 per unit of rated MW.

Similarly, induction generator installations, including Type 1 and Type 2 wind turbines, often include static and/or dynamic reactive devices to meet grid code requirements and may have apparent power output similar to inverter-based installations; therefore, it is appropriate to use the criteria established in the Table 1 (i.e., Options 4, 5, 6, 10, 11, 12, 17, 18, and 19) for asynchronous generator installations.

Synchronous Generator Simulation Criteria

The Generator Owner, Transmission Owner, or Distribution Provider who elects a simulation option to determine the synchronous generator performance on which to base relay settings may simulate the response of a generator by lowering the Transmission system voltage at the remote end of the line or at the high-side of the GSU transformer (as prescribed by the Table 1 criteria). This can be simulated by means such as modeling the connection of a shunt reactor at the remote end of the line or at the GSU transformer high-side to lower the voltage to 0.85 per unit prior to field-forcing. The resulting step change in voltage is similar to the sudden voltage depression observed in parts of the Transmission system on August 14, 2003. The initial condition for the simulation should represent the generator at 100 percent of the maximum gross Real Power capability in MW as reported to the Transmission Planner. The simulation is used to determine the Reactive Power and voltage to be used to calculate relay setting limits. The Reactive Power value obtained by simulation is the highest simulated level of Reactive Power achieved during field-forcing. The voltage value obtained by simulation is the simulated voltage coincident with the highest Reactive Power achieved during field-forcing. These values of Reactive Power and voltage correspond to the minimum apparent impedance and maximum current observed during field-forcing.

Phase Distance Relay – Directional Toward Transmission System (e.g., 21)

Generator phase distance relays that are directional toward the Transmission system, whether applied for the purpose of primary or backup GSU transformer protection, external system backup protection, or both, were noted during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, which contributed to the scope of that disturbance. Specifically, eight generators are known to have been tripped by this protection function. These options establish criteria for phase distance relays that are directional toward the Transmission system to help assure that generators, to the degree possible, will provide System support during disturbances in an effort to minimize the scope of those disturbances.

The phase distance relay that is directional toward the Transmission system measures impedance derived from the quotient of generator terminal voltage divided by generator stator current.

Section 4.6.1.1 of IEEE C37.102-2006, "Guide for AC Generator Protection," describes the purpose of this protection as follows (emphasis added):

> *"The distance relay applied for this function is intended to isolate the generator from the power system for a fault* ***that is not cleared by the transmission line breakers.*** *In some cases this relay is set with a very long reach. A condition that causes the generator voltage regulator to boost generator excitation for a sustained period may result in the system apparent impedance, as monitored at the generator terminals, to fall within the operating characteristics of the distance relay. Generally, a distance relay setting of 150% to 200% of the generator MVA rating at its rated power factor has been shown to provide good coordination for stable swings, system faults involving in-feed, and* ***normal loading conditions.*** *However, this setting may also result in failure of the relay to operate for some line faults where the line relays fail to clear. It is recommended that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers* ***to optimize coordination while still protecting the turbine generator****. Stability studies may be needed to help determine a set point to optimize protection and coordination. Modern excitation control systems include overexcitation limiting and protection devices to protect the generator field, but the time delay before they reduce excitation is several seconds. In distance relay applications for which the voltage regulator action could cause an incorrect trip, consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective devices in the voltage regulator. Digital multifunction relays equipped with load encroachment binders [sic] can prevent misoperation for these conditions.* ***Within its operating zone, the tripping time for this relay must coordinate with the longest time delay for the phase distance relays on the transmission lines connected to the generating substation bus.*** *With the advent of multifunction generator protection relays, it is becoming more common to use two-phase distance zones. In this case, the second zone would be set as previously described. When two zones are applied for backup protection, the first zone is typically set to see the substation bus (120% of the GSU transformer). This setting should be checked for coordination with the zone-1 element on the shortest line off of the bus. The normal zone-2 time-delay criteria would be used to set the*

delay for this element. Alternatively, zone-1 can be used to provide high-speed protection for phase faults, in addition to the normal differential protection, in the generator and iso-phase bus with partial coverage of the GSU transformer. For this application, the element would typically be set to 50% of the transformer impedance with little or no intentional time delay. It should be noted that it is possible that this element can operate on an out-of-step power swing condition and provide misleading targeting."

If a mho phase distance relay that is directional toward the Transmission system cannot be set to maintain reliable fault protection and also meet the criteria in accordance with Table 1, there may be other methods available to do both, such as application of blinders to the existing relays, implementation of lenticular characteristic relays, application of offset mho relays, or implementation of load encroachment characteristics. Some methods are better suited to improving loadability around a specific operating point, while others improve loadability for a wider area of potential operating points in the R-X plane. The operating point for a stressed System condition can vary due to the pre-event system conditions, severity of the initiating event, and generator characteristics such as Reactive Power capability.

For this reason, it is important to consider the potential implications of revising the shape of the relay characteristic to obtain a longer relay reach, as this practice may result in a relay characteristic that overlaps the capability of the generating unit when operating at a Real Power output level other than 100 percent of the maximum Real Power capability. Overlap of the relay characteristic and generator capability could result in tripping the generating unit for a loading condition within the generating unit capability. The examples in Appendix E of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document illustrate the potential for, and need to avoid, encroaching on the generating unit capability.

Phase Instantaneous Overcurrent Relay (e.g., 50)

The 50 element is a non-directional overcurrent element that typically has no intentional time delay. The primary application is for close-in high current faults where high speed operation is required or preferred. The instantaneous overcurrent elements are subject to the same loadability issues as the time overcurrent elements referenced in this standard.

Phase Time Overcurrent Relay (e.g., 51)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function. Note that the setting criteria established within the Table 1 options differs from the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Phase Time Overcurrent Relay – Voltage-Restrained (e.g., 51V-R)

Phase time overcurrent voltage-restrained relays (e.g., 51V-R), which change their sensitivity as a function of voltage, whether applied for the purpose of primary or backup GSU transformer protection, for external system phase backup protection, or both, were noted, during analysis of the August 14, 2003 disturbance event to have unnecessarily or prematurely tripped a number of generating units or generating plants, contributing to the scope of that disturbance. Specifically, 20 generators are known to have been tripped by voltage-restrained and voltage-controlled protection functions together. These protective functions are variably referred to by IEEE function numbers 51V, 51R, 51VR, 51V/R, 51V-R, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C)

Phase time overcurrent voltage-controlled relays (e.g., 51V-C), enabled as a function of voltage, are variably referred to by IEEE function numbers 51V, 51C, 51VC, 51V/C, 51V-C, or other terms. See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of this protection function.

Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67)

See Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document for a detailed discussion of the phase time overcurrent protection function. The basis for setting directional and non-directional overcurrent relays is similar. Note that the setting criteria established within the Table 1 options differs from of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator MVA rating at rated power factor for all applications, the Table 1 setting criteria are based on the maximum expected generator Real Power output based on whether the generator is a synchronous or asynchronous unit.

Table 1, Options

Introduction

The margins in the Table 1 options are based on guidance found in the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. The generator bus voltage during field-forcing will be higher than the high-side voltage due to the voltage drop across the GSU transformer. When the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator bus voltage.

Relay Connections

Figures 4 and 5 below illustrate the connections for each of the Table 1 options provided in PRC-025-2, Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria.

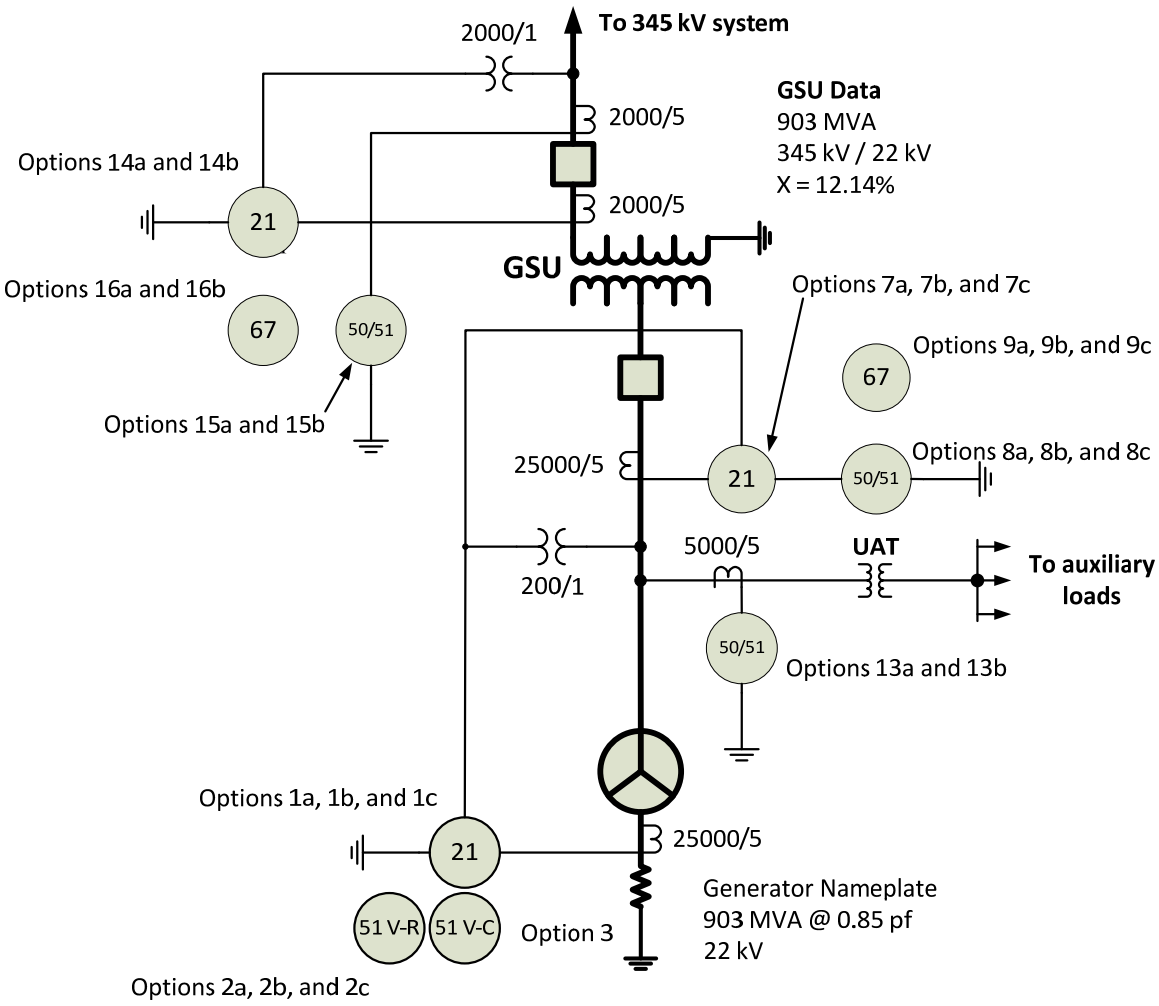


Figure 4. Relay Connection for corresponding synchronous options.

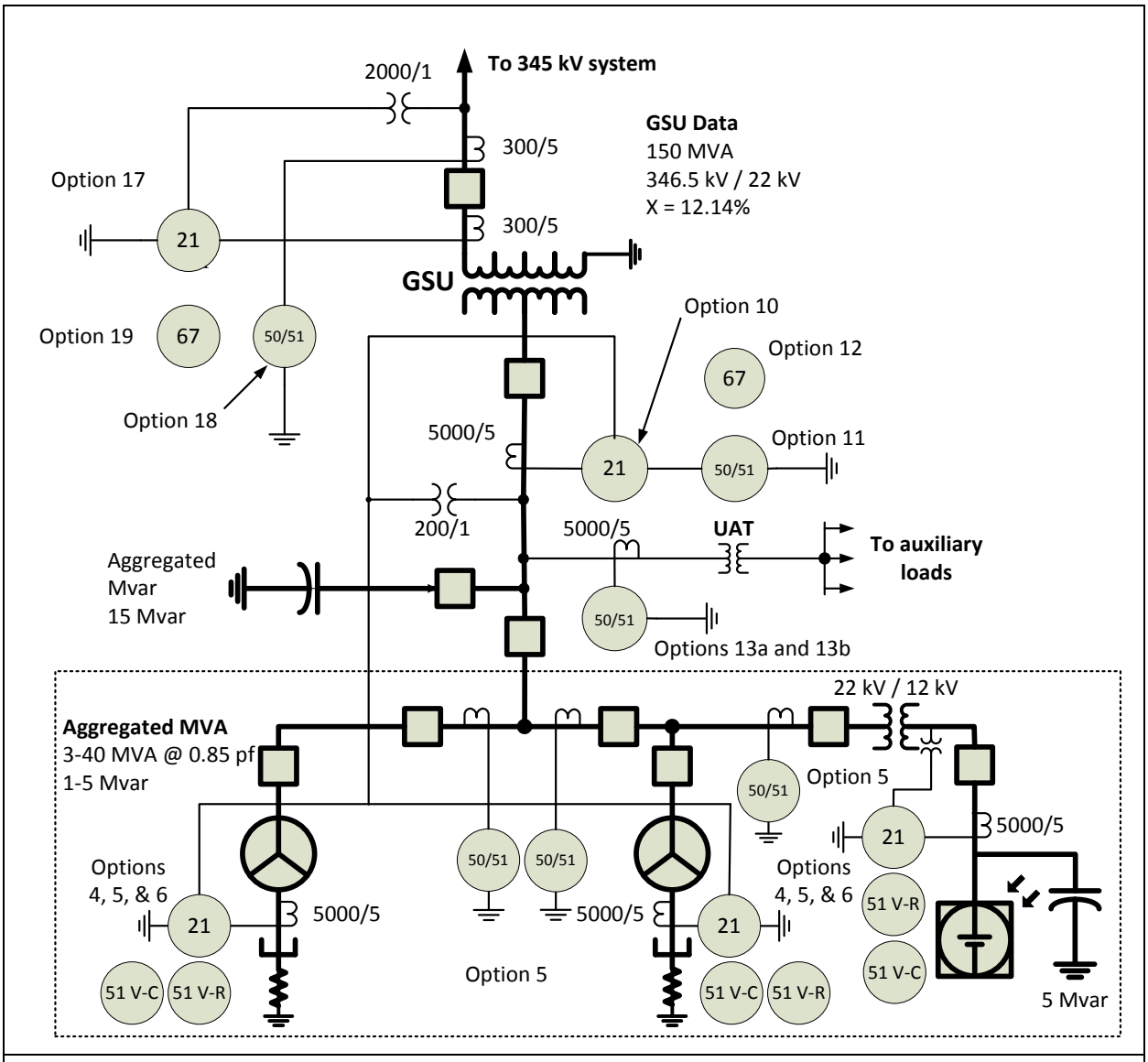


Figure 5. Relay Connection for corresponding asynchronous options including inverter-based installations.

Synchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Options 1a, 1b, and 1c)

Table 1, Options 1a, 1b, and 1c, are provided for assessing loadability for synchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 1a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 1b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting of the impedance element than Option 1a.

Option 1c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the impedance element overall.

For Options 1a and 1b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 1c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 2a, 2b, and 2c)

Table 1, Options 2a, 2b, and 2c, are provided for assessing loadability for synchronous generators applying phase overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 2a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 2b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on a 0.85 per unit nominal voltage at the high-side terminals of the GSU transformer as well as for the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved.

This calculation is a more in-depth and precise method for setting of the overcurrent element than Option 2a.

Option 2c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Options 2a and 2b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the MW value, derived from the generator nameplate MVA rating at rated power factor.

For Option 2c, the overcurrent element shall be set greater than the calculated current derived from 115 percent of both: the Real Power output of 100 percent of the maximum gross MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Synchronous Generators Phase Time Overcurrent Relay – Voltage Controlled (e.g., 51V-C) (Option 3)

Table 1, Option 3, is provided for assessing loadability for synchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 3 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 3, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Asynchronous Generators Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 4)

Table 1, Option 4 is provided for assessing loadability for asynchronous generators applying phase distance relays that are directional toward the Transmission system. These margins are

based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 4 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 4, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Asynchronous Generators Phase Overcurrent Relay – (e.g., 50, 51, or 51V-R – Voltage Restrained) (Options 5a and 5b)

Table 1, Option 5a is provided for assessing loadability for asynchronous generators applying phase overcurrent relays (e.g., 50 or 51) or voltage-restrained (e.g., 51V-R) which changes its sensitivity as a function of voltage ("voltage-restrained"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 5a calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 5a, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

For Option 5b, the overcurrent element shall be set to exceed the maximum capability of the asynchronous resource and applicable equipment (e.g., windings, power electronics, cables, or bus). This is determined by summing the total current capability of the generation equipment behind the overcurrent element and any static or dynamic Reactive Power devices that contribute to the power flow through the overcurrent element. The overcurrent element shall be set to not infringe upon the resource capability with worst case documented tolerances applied to the setting. Figure A illustrates that the overcurrent element does not infringe upon the asynchronous resource capability. The upper hashed area of Figure A represents Exclusion 7.

Asynchronous Generator Phase Time Overcurrent Relays – Voltage Controlled (e.g., 51V-C) (Option 6)

Table 1, Option 6, is provided for assessing loadability for asynchronous generators applying phase time overcurrent relays which are enabled as a function of voltage ("voltage-controlled"). These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Option 6 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This is a simple calculation that approximates the stressed system conditions.

For Option 6, the voltage control setting shall be set less than 75 percent of the calculated generator bus voltage. The voltage setting must be set such that the function (e.g., 51V-C) will not trip under extreme emergency conditions as the time overcurrent function will be set less than generator full load current. Relays enabled as a function of voltage are indifferent as to the current setting, and this option simply requires that the relays not respond for the depressed voltage.

Generator Step-up Transformer (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 7a, 7b, and 7c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Options 7a, 7b, and 7c, are provided for assessing loadability of phase distance relays that are directional toward the Transmission system and connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 14.

Option 7a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 7b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the impedance element than Option 7a.

Option 7c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the impedance element than Options 7a or 7b.

For Options 7a and 7b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 7c, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Options 8a, 8b and 8c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator

nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 8a, 8b, and 8c, are provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 15.

Option 8a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 8b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 8a.

Option 8c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 8a or 8b.

For Options 8a and 8b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 8c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 9a, 9b and 9c)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the

setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Options 9a, 9b, and 9c, are provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of a synchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 16.

Option 9a calculates a generator bus voltage corresponding to 0.95 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 0.95 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Option 9b calculates the generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer. The voltage drop across the GSU transformer is calculated based on the 0.85 per unit nominal voltage, at the high-side terminals of the GSU transformer, as well as the turns ratio and impedance. The actual generator bus voltage may be higher depending on the GSU transformer impedance and the actual Reactive Power achieved. This calculation is a more in-depth and precise method for setting the overcurrent element than Option 9a.

Option 9c simulates the generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing. This output is in response to a 0.85 per unit nominal voltage on the high-side terminals of the GSU transformer prior to field-forcing. Using simulation is a more in-depth and precise method for setting the overcurrent element than Options 9a or 9b.

For Options 9a and 9b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 150 percent of the aggregate generation MW value (derived from the generator nameplate MVA rating at rated power factor).

For Option 9c, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation.

Generator Step-up Transformer (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 10)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Table 1, Option 10 is provided for assessing loadability for GSU transformers applying phase distance relays that are directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. For applications where the relay is connected on the high-side of the GSU transformer, use Option 17.

Option 10 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay voltage is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 10, the impedance element shall be set less than the calculated impedance, derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 or 51) (Option 11)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 11 is provided for assessing loadability of phase overcurrent relays that are connected to the generator-side of the GSU transformer of an asynchronous generator. For

applications where the relay is connected on the high-side of the GSU transformer, use Option 18.

Option 11 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 11, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Generator Step-up Transformer (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 12)

The Federal Energy Regulatory Commission, in FERC Order No. 733, paragraph 104, directs that NERC address relay loadability for protective relays applied on GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform loadability threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 12 is provided for assessing loadability of phase directional overcurrent relays directional toward the Transmission System that are connected to the generator-side of the GSU transformer of an asynchronous generator. For applications where the relay is connected on the high-side of the GSU transformer, use Option 19.

Option 12 calculates the generator bus voltage corresponding to 1.0 per unit nominal voltage on the high-side terminals of the GSU transformer. The generator bus voltage is calculated by multiplying the 1.0 per unit nominal voltage, at the high-side terminals of the GSU transformer, by the GSU transformer turns ratio (excluding the impedance). This calculation is a straightforward way to approximate the stressed system conditions.

Since the relay current is supplied from the generator bus, it is necessary to assess loadability using the generator-side voltage. Asynchronous generators do not produce as much Reactive Power as synchronous generators; hence the voltage drop due to Reactive Power flow through the GSU transformer is not as significant. Therefore, the generator bus voltage can be conservatively estimated by reflecting the high-side nominal voltage to the generator-side based on the GSU transformer's turns ratio.

For Option 12, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor, including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay.

Unit Auxiliary Transformers Phase Overcurrent Relay (e.g., 50 or 51) (Options 13a and 13b)

In FERC Order No. 733, paragraph 104, directs NERC to include in this standard a loadability requirement for relays used for overload protection of the UAT that supply normal station service for a generating unit. For the purposes of this standard, UATs provide the overall station power to support the unit at its maximum gross operation.

Table 1, Options 13a and 13b provide two options for addressing phase overcurrent relaying applied at the high-side of UATs. The transformer high-side winding may be directly connected to the transmission grid or at the generator isolated phase bus (IPB) or iso-phase bus. Phase overcurrent relays applied at the high-side of the UAT that remove the transformer from service resulting in an immediate (e.g., via lockout or auxiliary tripping relay operation) or consequential trip of the associated generator are to be compliant with the relay setting criteria in this standard. Due to the complexity of the application of low-side overload relays for single or multi-winding transformers, phase overcurrent relaying applied at the low-side of the UAT are not addressed in this standard. These relays include, but are not limited to, a relay used for arc flash protection, feeder protection relays, breaker failure, and relays whose operation may result in a generator runback. Although the UAT is not directly in the output path from the generator to the Transmission system, it is an essential component for operation of the generating unit or plant.

Refer to the Figures 6 and 7 below for example configurations:

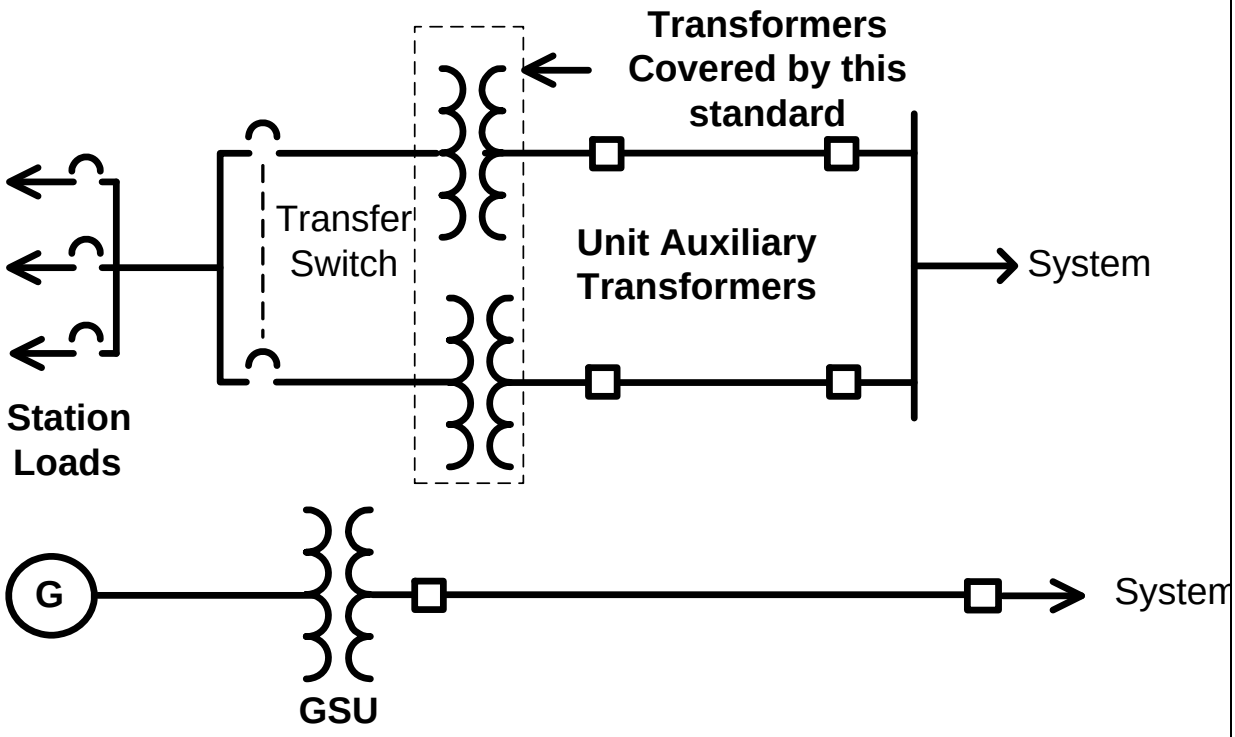


Figure-6 – Auxiliary Power System (independent from generator).

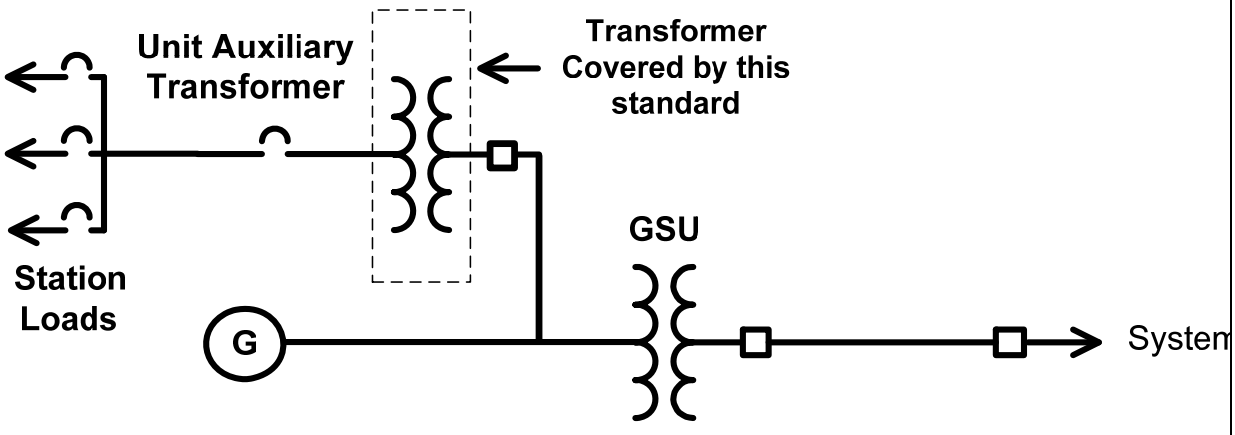


Figure-7 – Typical auxiliary power system for generation units or plants.

The UATs supplying power to the unit or plant electrical auxiliaries are sized to accommodate the maximum expected overall UAT load demand at the highest generator output. Although the transformer nameplate MVA size normally includes capacity for future loads as well as capacity for starting of large induction motors on the original unit or plant design, the nameplate MVA capacity of the transformer may be near full load.

Because of the various design and loading characteristics of UATs, two options (i.e., 13a and 13b) are provided to accommodate an entity's protection philosophy while preventing the UAT transformer phase overcurrent relays from operating during the dynamic conditions anticipated by this standard.

Options 13a and 13b are based on the transformer bus voltage corresponding to 1.0 per unit nominal voltage on the high-side winding of the UAT.

For Option 13a, the overcurrent element shall be set greater than 150 percent of the calculated current derived from the UAT maximum nameplate MVA rating. This is a simple calculation that approximates the stressed system conditions.

For Option 13b, the overcurrent element shall be set greater than 150 percent of the UAT measured current at the generator maximum gross MW capability reported to the Transmission Planner. This allows for a reduced setting compared to Option 13a and the entity's relay setting philosophy. This is a more involved calculation that approximates the stressed system conditions by allowing the entity to consider the actual load placed on the UAT based on the generator's maximum gross MW capability reported to the Transmission Planner.

The performance of the UAT loads during stressed system conditions (i.e., depressed voltages) is very difficult to determine. Rather than requiring responsible entities to determine the response of UAT loads to depressed voltage, the technical experts writing the standard elected to increase the margin to 150 percent from that used elsewhere in this standard (e.g., 115 percent) and use a generator bus voltage of 1.0 per unit. A minimum setting current based on 150 percent of maximum transformer nameplate MVA rating at 1.0 per unit generator bus voltage will provide adequate transformer protection based on IEEE C37.91 at full load conditions while providing sufficient relay loadability to prevent a trip of the UAT, and subsequent unit trip, due to increased UAT load current during stressed system voltage conditions. Even if the UAT is equipped with an automatic tap changer, the tap changer may not respond quickly enough for the conditions anticipated within this standard, and thus shall not be used to reduce this margin.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (e.g., 21) (Options 14a and 14b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers.

These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 14 is used for these relays as well.

Table 1, Options 14a and 14b, establish criteria for phase distance relays directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 14a reflects a 0.85 per unit of the line nominal voltage; therefore, establishing that the impedance value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase distance relays that are directional toward the Transmission system be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 14b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 14a, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 14b, the impedance element shall be set less than the calculated impedance derived from 115 percent of both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the impedance element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Time Overcurrent Relay (e.g., 50 or 51) (Options 15a and 15b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system (e.g., at the remote end of the line) that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 15 is used for these relays as well.

Table 1, Options 15a and 15b, establish criteria for phase instantaneous and/or time overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 15a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant phase instantaneous and/or time overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 15b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 15a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 15b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Synchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Options 16a and 16b)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output. Relays applied on the high-side of the GSU transformer respond to the same quantities as the relays connected on the Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, thus Option 16 is used for these relays as well.

Table 1, Options 16a and 16b, establish criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. The stressed system conditions, anticipated by Option 16a reflects a 0.85 per unit of the line nominal voltage at the relay location; therefore, establishing that the current value used for applying the interconnection Facilities phase directional overcurrent relays be calculated from the apparent power addressed within the criteria, with application of a 0.85 per unit of the line nominal voltage at the relay location. Consideration of the voltage drop across the GSU transformer is not necessary. Option 16b simulates the line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit line nominal voltage at the remote end of the line prior to field-forcing. Using a 0.85 per unit line nominal voltage at the remote end of the line is representative of the lowest voltage expected during a depressed voltage condition on Elements that are used exclusively to export energy directly from a BES generating unit or generating plant to the Transmission system. Using simulation is a more involved, more precise setting of the overcurrent element overall.

For Option 16a, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that

equates to 120 percent of the aggregate generation MW value, derived from the generator nameplate MVA rating at rated power factor. This Reactive Power value differs from the 150 percent multiplier used in other applications to account for the Reactive Power losses in the GSU transformer. This is a simple calculation that approximates the stressed system conditions.

For Option 16b, the overcurrent element shall be set greater than 115 percent of the calculated current derived from both: the Real Power output of 100 percent of the aggregate generation MW capability reported to the Transmission Planner, and the Reactive Power output that equates to 100 percent of the maximum gross Mvar output during field-forcing as determined by simulation. Using simulation is a more involved, more precise setting of the overcurrent element overall.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Distance Relay – Directional Toward Transmission System (e.g., 21) (Option 17)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. These margins are based on guidance found in Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document.

Table 1, Option 17 establishes criteria for phase distance relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 17 applies a 1.0 per unit line nominal voltage at the relay location to calculate the impedance from the maximum aggregate nameplate MVA.

For Option 17, the impedance element shall be set less than the calculated impedance derived from 130 percent of the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Overcurrent Relay (e.g., 50 and 51) (Option 18)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical

reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 18 establishes criteria for phase overcurrent relays to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 18 applies a 1.0 per unit line nominal voltage at the location of the relay to calculate the current from the maximum aggregate nameplate MVA.

For Option 18, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant (Asynchronous Generators) Phase Directional Overcurrent Relay – Directional Toward Transmission System (e.g., 67) (Option 19)

Relays applied on Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant are challenged by loading conditions similar to relays applied on generators and GSU transformers. Note that the setting criteria established within the Table 1 options differs from Chapter 2 of the Considerations for Power Plant and Transmission System Protection Coordination technical reference document. Rather than establishing a uniform setting threshold of 200 percent of the generator nameplate MVA rating at rated power factor for all applications, the setting criteria are based on the maximum expected generator output.

Table 1, Option 19 establishes criteria for phase directional overcurrent relays that are directional toward the Transmission system to prevent Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant from tripping during the dynamic conditions anticipated by this standard. Option 19 applies a 1.0 per unit line nominal voltage at the relay location to calculate the current from the maximum aggregate nameplate MVA.

For Option 19, the overcurrent element shall be set greater than 130 percent of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor including the Mvar output of any static or dynamic Reactive Power devices. This is determined by summing the total MW and Mvar capability of the generation equipment behind the relay and any static or dynamic Reactive Power devices that contribute to the power flow through the relay. This is a simple calculation that approximates the stressed system conditions.

Example Calculations

Introduction

Example Calculations.	
Input Descriptions	**Input Values**
Synchronous Generator nameplate (MVA @ rated pf):	$GEN_{Synch_nameplate} = 903\ MVA$
	$pf = 0.85$
Generator rated voltage (Line-to-Line):	$V_{gen_nom} = 22\ kV$
Real Power output in MW as reported to the TP:	$P_{Synch_reported} = 700.0\ MW$
Generator step-up (GSU) transformer rating:	$MVA_{GSU} = 903\ MVA$
GSU transformer reactance (903 MVA base):	$X_{GSU} = 12.14\%$
GSU transformer MVA base:	$MVA_{base} = 767.6\ MVA$
GSU transformer turns ratio:	$GSU_{ratio} = \frac{22\ kV}{346.5\ kV}$
High-side nominal system voltage (Line-to-Line):	$V_{nom} = 345\ kV$
Current transformer (CT) ratio:	$CT_{ratio} = \frac{25000}{5}$
Potential transformer (PT) ratio low-side:	$PT_{ratio} = \frac{200}{1}$
PT ratio high-side:	$PT_{ratio_hv} = \frac{2000}{1}$
Unit auxiliary transformer (UAT) nameplate:	$UAT_{nameplate} = 60\ MVA$
UAT low-side voltage:	$V_{UAT} = 13.8\ kV$
UAT CT ratio:	$CT_{UAT} = \frac{5000}{5}$
CT high voltage ratio:	$CT_{ratio_hv} = \frac{2000}{5}$
Reactive Power output of static reactive device:	$MVAR_{static} = 15\ Mvar$

Example Calculations.	
Reactive Power output of static reactive device generation:	$MVAR_{gen_static} = 5\ Mvar$
Asynchronous generator nameplate (MVA @ rated pf):	$GEN_{Asynch_nameplate} = 40\ MVA$
	$pf = 0.85$
Asynchronous CT ratio:	$CT_{Asynch_ratio} = \frac{5000}{5}$
Asynchronous high voltage CT ratio:	$CT_{Asynch_ratio_hv} = \frac{300}{5}$
CT remote substation bus	$CT_{ratio_remote_bus} = \frac{2000}{5}$

Example Calculations: Option 1a

Option 1a represents the simplest calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (1) $P = GEN_{Synch_nameplate} \times pf$

$P = 903\ MVA \times 0.85$

$P = 767.6\ MW$

Reactive Power output (Q):

Eq. (2) $Q = 150\% \times P$

$Q = 1.50 \times 767.6\ MW$

$Q = 1151.3\ Mvar$

Option 1a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (3) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$

$V_{gen} = 20.81\ kV$

Apparent power (S):

Eq. (4) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4\angle 58.7°\ MVA$

Primary impedance (Z_{pri}):

Eq. (5) $Z_{pri} = \frac{V_{gen}^2}{S^*}$

$Z_{pri} = \frac{(20.81\ kV)^2}{1347.4\angle -58.7°\ MVA}$

Example Calculations: Option 1a

$$Z_{pri} = 0.321\angle 58.7° \, \Omega$$

Secondary impedance (Z_{sec}):

Eq. (6) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.321\angle 58.7° \, \Omega \times 25$$

$$Z_{sec} = 8.035\angle 58.7° \, \Omega$$

To satisfy the 115% margin in Option 1a:

Eq. (7) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.035\angle 58.7° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 6.9873\angle 58.7° \, \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (8) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{\cos(85.0° - 58.7°)}$$

$$Z_{max} < \frac{6.9873 \, \Omega}{0.896}$$

$$Z_{max} < \ 7.793\angle 85.0° \, \Omega$$

Example Calculations: Options 1b and 7b

Option 1b represents a more complex, more precise calculation for synchronous generators applying a phase distance relay (e.g., 21) directional toward the Transmission system. This option requires calculating low-side voltage taking into account voltage drop across the GSU transformer. Similarly these calculations may be applied to Option 7b for GSU transformers applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (9) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (10) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on a 767.6 MVA base (MVA_{base}):

Real Power output (P):

Eq. (11) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (12) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Example Calculations: Options 1b and 7b

Transformer impedance (X_{pu}):

Eq. (13) $$X_{pu} = X_{GSU(old)} \times \left(\frac{MVA_{base}}{MVA_{GSU}}\right)$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (14) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (15)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Example Calculations: Options 1b and 7b

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (16) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (17)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (18) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Apparent power (S):

Eq. (19) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4\angle 58.7°\ MVA$$

Example Calculations: Options 1b and 7b

Primary impedance (Z_{pri}):

Eq. (20) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(21.90\ kV)^2}{1347.4\angle -58.7°\ MVA}$$

$$Z_{pri} = 0.356\angle 58.7°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (21) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.356\angle 58.7°\ \Omega \times 25$$

$$Z_{sec} = 8.900\angle 58.7°\ \Omega$$

To satisfy the 115% margin in Options 1b and 7b:

Eq. (22) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{8.900\angle 58.7°\ \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 7.74\angle 58.7°\ \Omega$$

$$\theta_{transient\ load\ angle} = 58.7°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (23) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{7.74\ \Omega}{\cos(85.0° - 58.7°)}$$

Example Calculations: Options 1b and 7b

$$Z_{max} < \frac{7.74\ \Omega}{0.8965}$$

$$Z_{max} < 8.633 \angle 85.0°\ \Omega$$

Example Calculations: Options 1c and 7c

Option 1c represents a more involved, more precise setting of the impedance element. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 1a and 1b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

In this simulation the following values are derived:

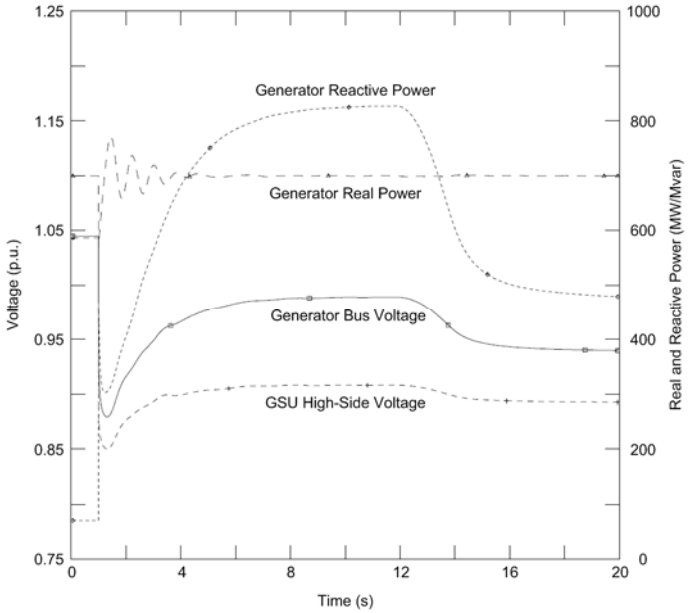
$$Q = 827.4\ Mvar$$

$$V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ k\text{V}$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$

Example Calculations: Options 1c and 7c



Apparent power (S):

Eq. (24) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (25) $$Z_{pri} = \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(21.76\ kV)^2}{1083.8\angle -49.8°\ MVA}$$

$$Z_{pri} = 0.437\angle 49.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (26) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.437\angle 49.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

Example Calculations: Options 1c and 7c

$$Z_{sec} = 0.437\angle 49.8° \, \Omega \times 25$$

$$Z_{sec} = 10.92\angle 49.8° \, \Omega$$

To satisfy the 115% margin in the requirement in Options 1c and 7c:

Eq. (27) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{10.92\angle 49.8° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 9.50\angle 49.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 49.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (28) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{9.50 \, \Omega}{\cos(85.0° - 49.8°)}$$

$$Z_{max} < \frac{9.50 \, \Omega}{0.8171}$$

$$Z_{max} < \ 11.63\angle 85.0° \, \Omega$$

Example Calculations: Option 2a

Option 2a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (29) $$P = \ GEN_{Synch_nameplate} \times pf$$

$$P = 903 \, MVA \ \times 0.85$$

$$P = 767.6 \, MW$$

Example Calculations: Option 2a

Reactive Power output (Q):

Eq. (30) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Option 2a, Table 1 – Bus Voltage, calls for a 0.95 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (31) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (32) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4 \angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (33) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (34) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

Example Calculations: Option 2a

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Option 2a:

Eq. (35) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.598\ A$$

Example Calculations: Option 2b

Option 2b represents a more complex calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay:

Real Power output (P):

Eq. (36) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (37) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (MVA_{base}).

Real Power output (P):

Eq. (38) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Example Calculations: Option 2b

Reactive Power output (Q):

Eq. (39) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (40) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (41) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.7°$$

Eq. (42)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Option 2b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (43) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times \lceil V_{high-side} \rceil)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (44)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (45) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Option 2b

Apparent power (S):

Eq. (46) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (47) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$

$I_{pri} = 35553\ A$

Secondary current (I_{sec}):

Eq. (48) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$

$I_{sec} = 7.111\ A$

To satisfy the 115% margin in Option 2b:

Eq. (49) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$

$I_{\mathrm{sec}\,limit} > 8.178\ A$

Example Calculations: Option 2c

Option 2c represents a more involved, more precise setting of the overcurrent element for the phase overcurrent (e.g., 50, 51, or 51V-R) relay. This option requires determining maximum generator Reactive Power output during field-forcing and the corresponding generator bus voltage. Once these values are determined, the remainder of the calculation is the same as Options 2a and 2b.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer during field-forcing is used as this value will correspond to the highest current. The corresponding generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a voltage-restrained phase overcurrent relay.

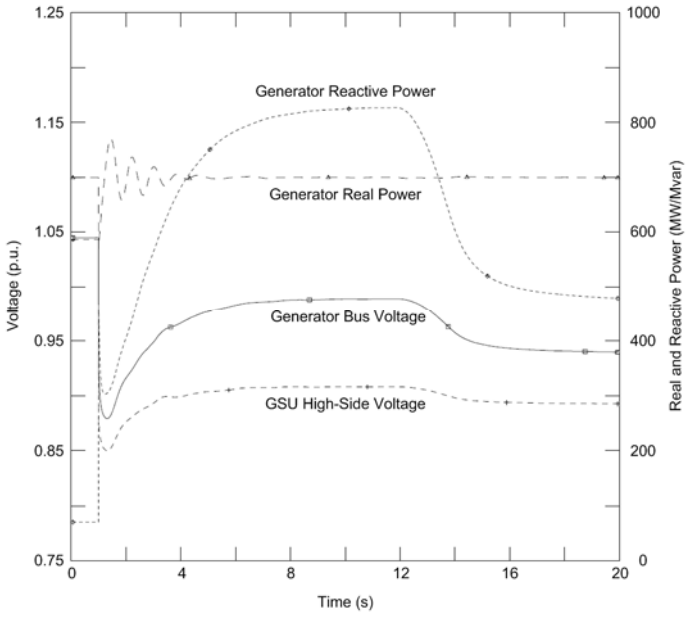
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus_simulated} = 0.989 \times V_{gen_nom} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{Synch_reported} = 700.0\ MW$$



Example Calculations: Option 2c

Apparent power (S):

Eq. (50) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j827.4\ Mvar$

$S = 1083.8 \angle 49.8°\ MVA$

Primary current (I_{pri}):

Eq. (51) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus_simulated}}$

$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$

$I_{pri} = 28790\ A$

Secondary current (I_{sec}):

Eq. (52) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$

$I_{sec} = 5.758\ A$

To satisfy the 115% margin in Option 2c:

Eq. (53) $I_{\text{sec}\,limit} > I_{sec} \times 115\%$

$I_{\text{sec}\,limit} > 5.758\ A \times 1.15$

$I_{\text{sec}\,limit} > 6.622\ A$

Example Calculations: Options 3 and 6

Option 3 represents the only calculation for synchronous generators applying a phase time overcurrent (e.g., 51V-C) relay (Enabled to operate as a function of voltage). Similarly, Option 6 uses the same calculation for asynchronous generators.

Example Calculations: Options 3 and 6

Options 3 and 6, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (54) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

The voltage setting shall be set less than 75% of the generator bus voltage:

Eq. (55) $$V_{setting} < V_{gen} \times 75\%$$

$$V_{setting} < 21.9\ kV\ \times 0.75$$

$$V_{setting} < 16.429\ kV$$

Example Calculations: Option 4

This represents the calculation for an asynchronous generator (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system.

Real Power output (P):

Eq. (56) $$P = GEN_{Asych_nameplate} \times pf$$

$$P = 40\ MVA\ \times 0.85$$

$$P = 34.0\ MW$$

Reactive Power output (Q):

Eq. (57) $$Q = GEN_{Async_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q = 40\ MVA \times \sin(\cos^{-1}(0.85))$$

$$Q = 21.1\ Mvar$$

Example Calculations: Option 4

Option 4, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (58) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (59) $$S = P + jQ$$

$$S = 34.0\ MW + j21.1\ Mvar$$

$$S = 40.0 \angle 31.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (60) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{40.0 \angle -31.8°\ MVA}$$

$$Z_{pri} = 11.99 \angle 31.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (61) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

$$Z_{sec} = 11.99 \angle 31.8°\ \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 11.99 \angle 31.8°\ \Omega \times 5$$

$$Z_{sec} = 59.95 \angle 31.8°\ \Omega$$

To satisfy the 130% margin in Option 4:

Eq. (62) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

Example Calculations: Option 4

$$Z_{\sec limit} = \frac{59.95\angle 31.8° \ \Omega}{1.30}$$

$$Z_{\sec limit} = 46.12\angle 31.8° \ \Omega$$

$$\theta_{transient\ load\ angle} = 31.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (63) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{46.12 \ \Omega}{\cos(85.0° - 31.8°)}$$

$$Z_{max} < \frac{46.12 \ \Omega}{0.599}$$

$$Z_{max} < \ 77.0\angle 85.0° \ \Omega$$

Example Calculations: Option 5a

This represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (64) $$P = \ 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40 \ MVA \ \times 0.85$$

$$P = 102.0 \ MW$$

Reactive Power output (Q):

Eq. (65) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15 \ Mvar + 5 \ Mvar + (3 \times 40 \ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \ Mvar$$

Example Calculations: Option 5a

Option 5a, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (66) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (67) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (68) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (69) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Option 5a:

Eq. (70) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\mathrm{sec}\,limit} > 3.473\angle -39.2°\ A \times 1.30$$

Example Calculations: Option 5a

$$I_{\sec limit} > 4.52\angle -39.2° \; A$$

Example Calculations: Option 5b

Similarly to Option 5a, this example represents the calculation for three asynchronous generators applying a phase overcurrent (e.g., 50, 51, or 51V-R) relay. In this application it was assumed that 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (71) $$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40 \; MVA \times 0.85$$

$$P = 102.0 \; MW$$

Reactive Power output (Q):

Eq. (72) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2 \; Mvar$$

Option 5b, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (73) $$V_{gen} = 1.0 \; p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345 \; kV \times \left(\frac{22 \; kV}{346.5 \; kV}\right)$$

$$V_{gen} = 21.9 \; kV$$

Apparent power (S):

Eq. (74) $$S = P + jQ$$

$$S = 102.0 \; MW + j83.2 \; Mvar$$

$$S = 131.6\angle 39.2° \; MVA$$

Example Calculations: Option 5b

Primary current (I_{pri}):

Eq. (75) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6\angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473\angle -39.2°\ A$$

Secondary current (I_{sec}):

Eq. (76) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy Option 5b, the overcurrent element shall not infringe upon the resource capability (including the Mvar output of the resource and any static or dynamic reactive power devices) with worst case documented tolerances applied between the maximum resource capability and the overcurrent element (see Figure A).

Example Calculations: Options 7a and 10

These examples represent the calculation for a mixture of asynchronous (i.e., Option 10) and synchronous (i.e., Option 7a) generation (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Synchronous Generation (Option 7a)

Real Power output (P_{sync}):

Eq. (77) $$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times 0.85$$

$$P_{Synch} = 767.6\ MW$$

Example Calculations: Options 7a and 10

Reactive Power output (Q_{synch}):

Eq. (78) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ MW$$

Apparent power (S_{Synch}):

Eq. (79) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

Asynchronous Generation (Option 10)

Real Power output (P_{Asynch}):

Eq. (80) $$P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40\ MVA \times 0.85$$

$$P_{Asynch} = 102.0\ MW$$

Reactive Power output (Q_{Asynch}):

Eq. (81) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Apparent power (S_{Asynch}):

Eq. (82) $$S_{Asynch} = P_{Asynch} + jQ_{Asynch}$$

$$S_{Asynch} = 102.0\ MW + j83.2\ Mvar$$

Example Calculations: Options 7a and 10

Options 7a and 10, Table 1 – Bus Voltage, Option 7a specifies 0.95 per unit of the high-side nominal voltage for the generator bus voltage and Option 10 specifies 1.0 per unit of the high-side nominal voltage for generator bus voltage. Due to the presence of the synchronous generator, the 0.95 per unit bus voltage will be used as (V_{gen}) as it results in the most conservative voltage:

Eq. (83) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S) accounted for 115% margin requirement for a synchronous generator and 130% margin requirement for an asynchronous generator:

Eq. (84) $$S = 115\% \times \left(P_{Synch_reported} + jQ_{Synch}\right) + 130\% \times \left(P_{Asynch} + jQ_{Asynch}\right)$$

$$S = 1.15 \times (700.0\ MW + j1151.3\ Mvar) + 1.30 \times (102.0\ MW + j83.2\ Mvar)$$

$$S = 1711.8 \angle 56.8°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (85) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(20.81\ kV)^2}{1711.8\angle -56.8°\ MVA}$$

$$Z_{pri} = 0.2527\angle 56.8°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (86) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio}}{PT_{ratio}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times \frac{\frac{25000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 0.2527\angle 56.8°\ \Omega \times 25$$

$$Z_{sec} = 6.32\angle 56.8°\ \Omega$$

Example Calculations: Options 7a and 10

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 84 to satisfy the margin requirements in Options 7a and 10.

Eq. (87) $$Z_{\text{sec }limit} = \frac{Z_{sec}}{100\%}$$

$$Z_{\text{sec }limit} = \frac{6.32 \angle 56.8° \, \Omega}{1.00}$$

$$Z_{\text{sec }limit} = 6.32 \angle 56.8° \, \Omega$$

$$\theta_{transient\ load\ angle} = 56.8°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (88) $$Z_{max} < \frac{|Z_{\text{sec }limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{6.32 \, \Omega}{\cos(85.0° - 56.8°)}$$

$$Z_{max} < \frac{6.32 \, \Omega}{0.881}$$

$$Z_{max} < 7.17 \angle 85.0° \, \Omega$$

Example Calculations: Options 8a and 9a

Options 8a and 9a represents the simplest calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (89) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903 \, MVA \times 0.85$$

$$P = 767.6 \, MW$$

Example Calculations: Options 8a and 9a

Reactive Power output (Q):

Eq. (90) $Q = 150\% \times P$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Options 8a and 9a, Table 1 – Bus Voltage, calls for a generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer generator bus voltage (V_{gen}):

Eq. (91) $V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Apparent power (S):

Eq. (92) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j1151.3\ Mvar$$

$$S = 1347.4 \angle 58.7°\ MVA$$

Primary current (I_{pri}):

Eq. (93) $I_{pri} = \frac{S}{\sqrt{3} \times V_{gen}}$

$$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 20.81\ kV}$$

$$I_{pri} = 37383\ A$$

Secondary current (I_{sec}):

Eq. (94) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

Example Calculations: Options 8a and 9a

$$I_{sec} = \frac{37383\ A}{\frac{25000}{5}}$$

$$I_{sec} = 7.477\ A$$

To satisfy the 115% margin in Options 8a and 9a:

Eq. (95) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 7.477\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 8.598\ A$$

Example Calculations: Options 8b and 9b

Options 8b and 9b represents a more precise calculation for synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relay. The following uses the $GEN_{Synch_nameplate}$ value to represent an "aggregate" value to illustrate the option:

Real Power output (P):

Eq. (96) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (97) $$Q = 150\% \times P$$

$$Q = 1.50 \times 767.6\ MW$$

$$Q = 1151.3\ Mvar$$

Convert Real Power, Reactive Power, and transformer reactance to per unit values on 767.6 MVA base (GSU Transformer MVA_{base}).

Real Power output (P):

Eq. (98) $$P_{pu} = \frac{P_{Synch_reported}}{MVA_{base}}$$

Example Calculations: Options 8b and 9b

$$P_{pu} = \frac{700.0\ MW}{767.6\ MVA}$$

$$P_{pu} = 0.91\ p.u.$$

Reactive Power output (Q):

Eq. (99) $$Q_{pu} = \frac{Q}{MVA_{base}}$$

$$Q_{pu} = \frac{1151.3\ Mvar}{767.6\ MVA}$$

$$Q_{pu} = 1.5\ p.u.$$

Transformer impedance:

Eq. (100) $$X_{pu} = X_{GSU(old)} \times \frac{MVA_{base}}{MVA_{GSU}}$$

$$X_{pu} = 12.14\% \times \left(\frac{767.6\ MVA}{903\ MVA}\right)$$

$$X_{pu} = 0.1032\ p.u.$$

Using the formula below; calculate the low-side GSU transformer voltage ($V_{low\text{-}side}$) using 0.85 p.u. high-side voltage ($V_{high\text{-}side}$). Estimate initial low-side voltage to be 0.95 p.u. and repeat the calculation as necessary until $V_{low\text{-}side}$ converges. A convergence of less than one percent (<1%) between iterations is considered sufficient:

Eq. (101) $$\theta_{low-side} = \sin^{-1}\left[\frac{\left(P_{pu} \times |X_{pu}|\right)}{\left(|V_{low-side}| \times \lceil V_{high-side} \rceil\right)}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.95 \times 0.85)}\right]$$

Eq. (102)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.7°) \pm \sqrt{|0.85|^2 \times \cos^2(6.7°) + 4 \times 1.5 \times 0.1032}}{2}$$

Example Calculations: Options 8b and 9b

$$|V_{low-side}| = \frac{|0.85| \times 0.9931 \pm \sqrt{0.7225 \times 0.9864 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8441 \pm 1.1541}{2}$$

$$|V_{low-side}| = 0.9991\ p.u.$$

Use the new estimated $V_{low\text{-}side}$ value of 0.9991 per unit for the second iteration:

Eq. (103) $$\theta_{low-side} = \sin^{-1}\left[\frac{(P_{pu} \times |X_{pu}|)}{(|V_{low-side}| \times [V_{high-side}])}\right]$$

$$\theta_{low-side} = \sin^{-1}\left[\frac{(0.91 \times 0.1032)}{(0.9991 \times 0.85)}\right]$$

$$\theta_{low-side} = 6.3°$$

Eq. (104)

$$|V_{low-side}| = \frac{|V_{high-side}| \times \cos(\theta_{low-side}) \pm \sqrt{|V_{high-side}|^2 \times \cos^2(\theta_{low-side}) + 4 \times Q_{pu} \times X_{pu}}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times \cos(6.3°) \pm \sqrt{|0.85|^2 \times \cos^2(6.3°) + 4 \times 1.5 \times 0.1032}}{2}$$

$$|V_{low-side}| = \frac{|0.85| \times 0.9940 \pm \sqrt{0.7225 \times 0.9880 + 0.6192}}{2}$$

$$|V_{low-side}| = \frac{0.8449 \pm 1.1546}{2}$$

$$|V_{low-side}| = 0.9998\ p.u.$$

To account for system high-side nominal voltage and the transformer tap ratio:

Eq. (105) $$V_{bus} = |V_{low-side}| \times V_{nom} \times GSU_{ratio}$$

$$V_{bus} = 0.9998\ p.u. \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{bus} = 21.90\ kV$$

Example Calculations: Options 8b and 9b

Apparent power (S):

Eq. (106) $S = P_{Synch_reported} + jQ$

$S = 700.0\ MW + j1151.3\ Mvar$

$S = 1347.4 \angle 58.7°\ MVA$

Primary current (I_{pri}):

Eq. (107) $I_{pri} = \frac{S}{\sqrt{3} \times V_{bus}}$

$I_{pri} = \frac{1347.4\ MVA}{1.73 \times 21.90\ kV}$

$I_{pri} = 35553\ A$

Secondary current (I_{sec}):

Eq. (108) $I_{sec} = \frac{I_{pri}}{CT_{ratio}}$

$I_{sec} = \frac{35553\ A}{\frac{25000}{5}}$

$I_{sec} = 7.111\ A$

To satisfy the 115% margin in Options 8b and 9b:

Eq. (109) $I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$

$I_{\mathrm{sec}\,limit} > 7.111\ A \times 1.15$

$I_{\mathrm{sec}\,limit} > 8.178\ A$

Example Calculations: Options 8a, 9a, 11, and 12

This example represents the calculation for a mixture of asynchronous and synchronous generators applying a phase overcurrent (e.g., 50, 51, or 67) relays. In this application it was assumed 20 Mvar of total static compensation was added. The current transformers (CT) are located on the low-side of the GSU transformer.

Synchronous Generation (Options 8a and 9a)

Real Power output (P_{Synch}):

Eq. (110) $$P_{Synch} = GEN_{Synch_nameplate} \times pf$$

$$P_{Synch} = 903\ MVA \times .85$$

$$P_{Synch} = 767.6\ MW$$

Reactive Power output (Q_{Synch}):

Eq. (111) $$Q_{Synch} = 150\% \times P_{Synch}$$

$$Q_{Synch} = 1.50 \times 767.6\ MW$$

$$Q_{Synch} = 1151.3\ Mvar$$

Apparent power (S_{Synch}):

Eq. (112) $$S_{Synch} = P_{Synch_reported} + jQ_{Synch}$$

$$S_{Synch} = 700.0\ MW + j1151.3\ Mvar$$

$$S_{Synch} = 1347.4\ \angle 58.7°\ MVA$$

Option 8a, Table 1 – Bus Voltage calls for a 0.95 per unit of the high-side nominal voltage as a basis for generator bus voltage (V_{gen}):

Eq. (113) $$V_{gen} = 0.95\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 20.81\ kV$$

Example Calculations: Options 8a, 9a, 11, and 12

Primary current ($I_{pri\text{-}sync}$):

Eq. (114) $$I_{pri-sync} = \frac{115\% \times S^{*}_{Synch}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-sync} = \frac{1.15 \times (1347.4 \angle -58.7° \; MVA)}{1.73 \times 20.81 \; kV}$$

$$I_{pri-sync} = 43061 \angle -58.7° \; A$$

Asynchronous Generation (Options 11 and 12)

Real Power output (P_{Asynch}):

Eq. (115) $$P_{Asynch} = \; 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \; MVA \; \times 0.85$$

$$P_{Asynch} = 102.0 \; MW$$

Reactive Power output (Q_{Asynch}):

Eq. (116) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))$$

$$Q_{Asynch} = 15 \; Mvar + 5 \; Mvar + (3 \times 40 \; MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2 \; Mvar$$

Option 11, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}), however due to the presence of synchronous generator 0.95 per unit bus voltage will be used:

Eq. (117) $$V_{gen} = 0.95 \; p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 0.95 \times 345 \; kV \times \left(\frac{22 \; kV}{346.5 \; kV}\right)$$

$$V_{gen} \; = \; 20.81 \; kV$$

Apparent power (S_{Asynch}):

Eq. (118) $$S_{Asynch} = 130\% \; \times (P_{Asynch} + jQ_{Asynch})$$

$$S_{Asynch} = 1.30 \; \times (102.0 \; MW + j83.2 \; Mvar)$$

Example Calculations: Options 8a, 9a, 11, and 12

$$S_{Asynch} = 171.1 \angle 39.2° \; MVA$$

Primary current ($I_{pri\text{-}async}$):

Eq. (119) $$I_{pri-async} = \frac{S_{Asych}}{\sqrt{3} \times V_{gen}}$$

$$I_{pri-async} = \frac{171.1 \angle -39.2° \; MVA}{1.73 \; \times 20.81 \; kV}$$

$$I_{pri-async} = 4755 \angle -39.2° \; A$$

Secondary current (I_{sec}):

Eq. (120) $$I_{sec} = \frac{I_{pri-sync}}{CT_{ratio}} + \frac{I_{pri-async}}{CT_{ratio}}$$

$$I_{sec} = \frac{43061 \angle -58.7° \; A}{\frac{25000}{5}} + \frac{4755 \angle -39.2° \; A}{\frac{25000}{5}}$$

$$I_{sec} = 9.514 \angle -56.8° \; A$$

No additional margin is needed because the synchronous apparent power has been multiplied by 1.15 (115%) in Equation 114 and the asynchronous apparent power has been multiplied by 1.30 (130%) in Equation 118.

Eq. (121) $$I_{\text{sec}\,limit} > I_{sec} \times 100\%$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \; A \times 1.00$$

$$I_{\text{sec}\,limit} > 9.514 \angle -56.8° \; A$$

Example Calculations: Options 8c and 9c

This example uses Option 15b as a simulation example for a synchronous generator applying a phase overcurrent relay (e.g., 50, 51, or 67). In this application the same synchronous generator is modeled as for Options 1c, 2c, and 7c. The CTs are located on the low-side of the GSU transformer.

The generator Reactive Power and generator bus voltage are determined by simulation. The maximum Reactive Power output on the low-side of the GSU transformer, during field-forcing, is used since this value will correspond to the highest current. The corresponding

Example Calculations: Options 8c and 9c

generator bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

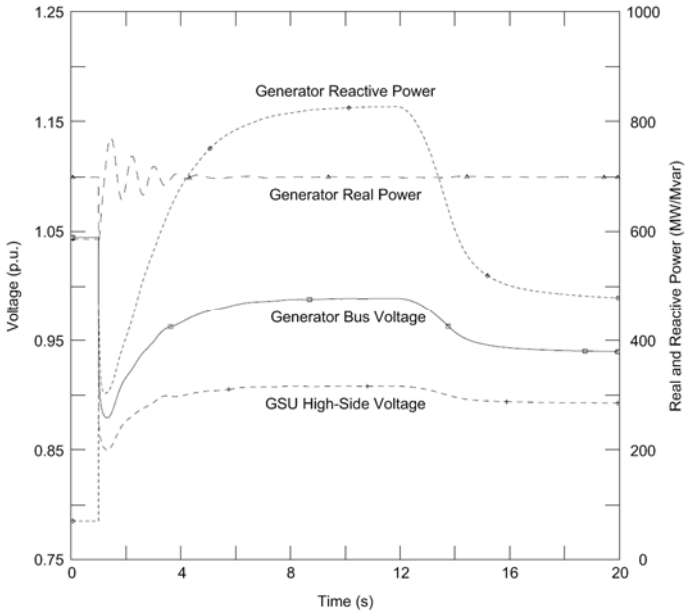
In this simulation the following values are derived:

$$Q = 827.4\ Mvar$$

$$V_{bus_simulated} = 0.989 \times V_{gen} = 21.76\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (122) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j827.4\ Mvar$$

$$S = 1083.8\angle 49.8°$$

Example Calculations: Options 8c and 9c

Primary current (I_{pri}):

Eq. (123) $$I_{pri} = \frac{S}{\sqrt{3} \times V_{bus_simulated}}$$

$$I_{pri} = \frac{1083.8\ MVA}{1.73 \times 21.76\ kV}$$

$$I_{pri} = 28790\ A$$

Secondary current (I_{sec}):

Eq. (124) $$I_{sec} = \frac{I_{pri}}{CT_{ratio}}$$

$$I_{sec} = \frac{28790\ A}{\frac{25000}{5}}$$

$$I_{sec} = 5.758\ A$$

To satisfy the 115% margin in Options 8c and 9c:

Eq. (125) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\mathrm{sec}\,limit} > 5.758\ A \times 1.15$$

$$I_{\mathrm{sec}\,limit} > 6.622\ A$$

Example Calculations: Option10

This example represents the calculation for three asynchronous generators (including inverter-based installations) applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (126) $$P = 3 \times GEN_{Asych_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

Example Calculations: Option10

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (127) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Option 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (128) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (129) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (130) $$Z_{pri} = \frac{V_{gen}^2}{S^*}$$

$$Z_{pri} = \frac{(21.9\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 3.644\ \angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (131) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio}}{PT_{ratio}}$$

Example Calculations: Option10

$$Z_{sec} = 3.644 \angle 39.2° \, \Omega \times \frac{\frac{5000}{5}}{\frac{200}{1}}$$

$$Z_{sec} = 3.644 \angle 39.2° \, \Omega \times 5$$

$$Z_{sec} = 18.22 \angle 39.2° \, \Omega$$

To satisfy the 130% margin in Option 10:

Eq. (132) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec}\,limit} = \frac{18.22 \angle 39.2° \, \Omega}{1.30}$$

$$Z_{\text{sec}\,limit} = 14.02 \angle 39.2° \, \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (133) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{14.02 \, \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{14.02 \, \Omega}{0.6972}$$

$$Z_{max} < \ 20.11 \angle 85.0° \, \Omega$$

Example Calculations: Options 11 and 12

Option 11 represents the calculation for a GSU transformer applying a phase overcurrent (e.g., 50 or 51) relay connected to three asynchronous generators. Similarly, these calculations can be applied to Option 12 for a phase directional overcurrent relay (e.g., 67) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 11 and 12

Real Power output (P):

Eq. (134) $$P = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (135) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 11 and 12, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for the generator bus voltage (V_{gen}):

Eq. (136) $$V_{gen} = 1.0\ p.u. \times V_{nom} \times GSU_{ratio}$$

$$V_{gen} = 1.0 \times 345\ kV \times \left(\frac{22\ kV}{346.5\ kV}\right)$$

$$V_{gen} = 21.9\ kV$$

Apparent power (S):

Eq. (137) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6 \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (138) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{gen}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 21.9\ kV}$$

$$I_{pri} = 3473 \angle -39.2°\ A$$

Example Calculations: Options 11 and 12

Secondary current (I_{sec}):

Eq. (139) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio}}$$

$$I_{sec} = \frac{3473\angle -39.2°\ A}{\frac{5000}{5}}$$

$$I_{sec} = 3.473\angle -39.2°\ A$$

To satisfy the 130% margin in Options 11 and12:

Eq. (140) $$I_{\text{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\text{sec}\,limit} > 3.473\angle -39.2°\ A \times 1.30$$

$$I_{\text{sec}\,limit} > 4.515\angle -39.2°\ A$$

Example Calculations: Options 13a and 13b

Option 13a for the UAT assumes the maximum nameplate rating of the winding is utilized for the purposes of the calculations and the appropriate voltage. Similarly, Option 13b uses the measured current while operating at the maximum gross MW capability reported to the Transmission Planner.

Primary current (I_{pri}):

Eq. (141) $$I_{pri} = \frac{UAT_{nameplate}}{\sqrt{3} \times V_{UAT}}$$

$$I_{pri} = \frac{60\ MVA}{1.73 \times 13.8\ kV}$$

$$I_{pri} = 2510.2\ A$$

Secondary current (I_{sec}):

Eq. (142) $$I_{sec} = \frac{I_{pri}}{CT_{UAT}}$$

Example Calculations: Options 13a and 13b

$$I_{sec} = \frac{2510.2\ A}{\frac{5000}{5}}$$

$$I_{sec} = 2.51\ \text{A}$$

To satisfy the 150% margin in Options 13a:

Eq. (143) $$I_{\text{sec}\,limit} > I_{sec} \times 150\%$$

$$I_{\text{sec}\,limit} > 2.51\ A \times 1.50$$

$$I_{\text{sec}\,limit} > 3.77\ A$$

Example Calculations: Option 14a

Option 14a represents the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

Real Power output (P):

Eq. (144) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (145) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.1\ Mvar$$

Option 14a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage for the GSU transformer voltage (V_{nom}):

Eq. (146) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

Example Calculations: Option 14a

$$V_{gen} = 0.85 \times 345\ kV$$

$$V_{gen} = 293.25\ kV$$

Apparent power (S):

Eq. (147) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.1\ Mvar$$

$$S = 1157.0\angle 52.77°\ MVA$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Primary impedance (Z_{pri}):

Eq. (148) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(293.25\ kV)^2}{1157.0\angle -52.77°\ MVA}$$

$$Z_{pri} = 74.335\angle 52.77°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (149) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 74.335\angle 52.77°\ \Omega \times 0.2$$

$$Z_{sec} = 14.867\angle 52.77°\ \Omega$$

To satisfy the 115% margin in Option 14a:

Eq. (150) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{14.867\angle 52.77°\ \Omega}{1.15}$$

Example Calculations: Option 14a

$$Z_{\sec limit} = 12.928\angle 52.77° \ \Omega$$

$$\theta_{transient\ load\ angle} = 52.77°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (151) $$Z_{max} < \frac{|Z_{\sec limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{12.928\ \Omega}{\cos(85.0° - 52.77°)}$$

$$Z_{max} < \frac{12.928\ \Omega}{0.846}$$

$$Z_{max} < \ 15.283\angle 85.0° \ \Omega$$

Example Calculations: Option 14b

Option 14b represents the simulation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. In this example, the Element is protected by a phase distance (e.g., 21) relay directional toward the Transmission system. The CTs are located on the high-side of the GSU transformer.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase distance relay.

In this simulation the following values are derived:

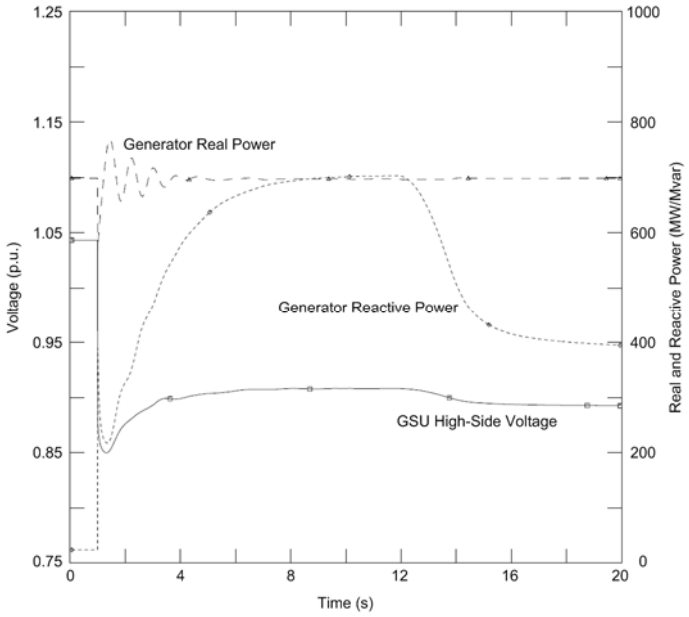
$$Q = 703.6\ Mvar$$

$$V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

Example Calculations: Option 14b

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (152) $S = P_{Synch_reported} + jQ$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Primary impedance (Z_{pri}):

Eq. (153) $$Z_{pri} = \frac{V_{bus_simulated}^2}{S^*}$$

$$Z_{pri} = \frac{(313.3\ kV)^2}{992.5\angle -45.1°\ MVA}$$

$$Z_{pri} = 98.90\angle 45.1°\ \Omega$$

Example Calculations: Option 14b

Secondary impedance (Z_{sec}):

Eq. (154) $$Z_{sec} = Z_{pri} \times \frac{CT_{ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times \frac{\frac{2000}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 98.90\angle 45.1° \, \Omega \times 0.2$$

$$Z_{sec} = 19.78\angle 45.1° \, \Omega$$

To satisfy the 115% margin in Option 14b:

Eq. (155) $$Z_{\text{sec}\,limit} = \frac{Z_{sec}}{115\%}$$

$$Z_{\text{sec}\,limit} = \frac{19.78\angle 45.1° \, \Omega}{1.15}$$

$$Z_{\text{sec}\,limit} = 17.20\angle 45.1° \, \Omega$$

$$\theta_{transient\ load\ angle} = 45.1°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, then the maximum allowable impedance reach is:

Eq. (156) $$Z_{max} < \frac{|Z_{\text{sec}\,limit}|}{\cos\left(\theta_{MTA} - \theta_{transient\ load\ angle}\right)}$$

$$Z_{max} < \frac{17.20 \, \Omega}{\cos(85.0° - 45.1°)}$$

$$Z_{max} < \frac{17.20 \, \Omega}{0.767}$$

$$Z_{max} < \ 22.42\angle 85.0° \, \Omega$$

Example Calculations: Options 15a and 16a

Options 15a and 16a represent the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. Option 15a represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line. Option 16a represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase time directional overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU transformer and remote end of the line.

Example calculations are provided for the case, where potential transformers (PT) and current transformers (CT) are located at the high-side of the GSU transformer. The 0.85 per unit of the line nominal voltage at the relay location will be at the high-side of the GSU transformer. Example calculations are also provided for the case where PTs and CTs are located at the remote end of the line and the 0.85 per unit of the line nominal voltage will be at the remote bus location.

Calculations at the high-side of the GSU transformer.

Real Power output (P):

Eq. (157) $$P = GEN_{Synch_nameplate} \times pf$$

$$P = 903\ MVA \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (158) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage:

Eq. (159) $$V_{bus} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus} = 0.85 \times 345\ kV$$

Example Calculations: Options 15a and 16a

$$V_{bus} = 293.25\ kV$$

Apparent power (S):

Eq. (160) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (161) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (162) $$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

$$I_{sec} = \frac{2280.6\angle -52.8°\ A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8°\ A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (163) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.701 \angle -52.8°\ A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.56 \angle -52.8°\ A$$

Calculations at the remote end of the line from the plant.

Real Power output (P):

Eq. (164) $$P = GEN_{Synch_nameplate} \times pf$$

Example Calculations: Options 15a and 16a

$$P = 903\ MVA\ \times 0.85$$

$$P = 767.6\ MW$$

Reactive Power output (Q):

Eq. (165) $$Q = 120\% \times P$$

$$Q = 1.20 \times 767.6\ MW$$

$$Q = 921.12\ Mvar$$

Option 15a and 16a, Table 1 – Bus Voltage, calls for a 0.85 per unit of the line nominal voltage at the relay location, in this example the relay location is at the remote substation bus.

Eq. (166) $$V_{bus_remote_substation} = 0.85\ p.u. \times V_{nom}$$

$$V_{bus_remote_substation} = 0.85 \times 345\ kV$$

$$V_{bus_remote_substation} = 293.25\ kV$$

Apparent power (S):

Eq. (167) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j921.12\ Mvar$$

$$S = 1157\angle 52.8°\ MVA$$

Primary current (I_{pri}):

Eq. (168) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus_remote_substation}}$$

$$I_{pri} = \frac{1157\angle -52.8°\ MVA}{1.73 \times 293.25\ kV}$$

$$I_{pri} = 2280.6\angle -52.8°\ A$$

Secondary current (I_{sec}):

Eq. (169) $$I_{sec} = \frac{I_{pri}}{CT_{CT_{ratio_remote_bus}}}$$

Example Calculations: Options 15a and 16a

$$I_{sec} = \frac{2280.6\angle -52.8° \; A}{\frac{2000}{5}}$$

$$I_{sec} = 5.701 \angle -52.8° \; A$$

To satisfy the 115% margin in Options 15a and 16a:

Eq. (170) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 5.701 \angle -52.8° \; A \times 1.15$$

$$I_{\text{sec}\,limit} > 6.56 \angle -52.8° \; A$$

Example Calculations: Options 15b and 16b

Options 15b and 16b represent the calculation for Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant connected to synchronous generation. Option 15b represents applying a phase time overcurrent relay (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line. Option 16b represents applying a phase directional instantaneous overcurrent supervisory element (e.g., 67) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications directional toward the Transmission system installed on the high-side of the GSU and at the remote end of the line and/or a phase directional time overcurrent relay (e.g., 67) directional toward the Transmission system installed on the high-side of the GSU and remote end of the line.

Example calculations are provided for the case, where PTs and CTs are located at the remote end of the line from the plant. The 0.85 per unit of the line nominal voltage is applied at the remote end of the line.

The Reactive Power flow and high-side bus voltage are determined by simulation. The maximum Reactive Power output on the high-side of the GSU transformer during field-forcing is used as this value will correspond to the lowest apparent impedance. The corresponding high-side bus voltage is also used in the calculation. Note that although the excitation limiter reduces the field, the duration of the Reactive Power output achieved for this condition is sufficient to operate a phase overcurrent relay.

Example Calculations: Options 15b and 16b

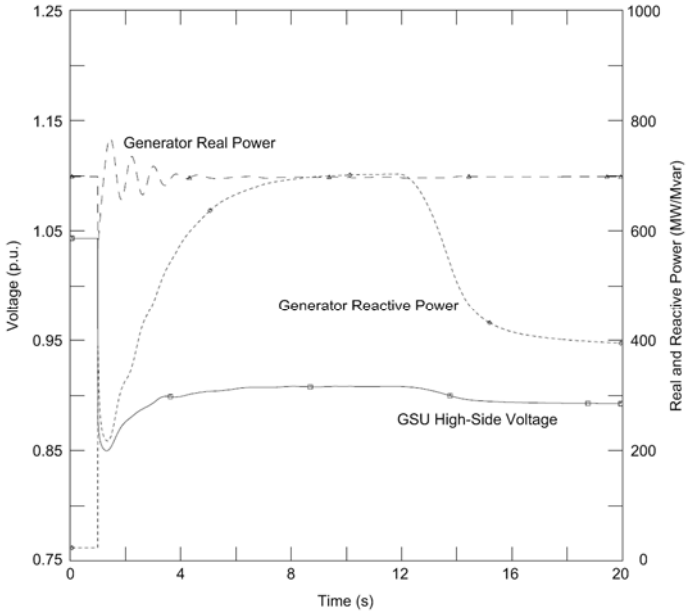
In this simulation the following values are derived:

$$Q = 703.6\ Mvar$$

$$V_{bus_simulated} = 0.908 \times V_{nom} = 313.3\ kV$$

The other value required is the Real Power output which is modeled in the simulation at 100% of the gross MW capability reported to the Transmission Planner. In this case:

$$P_{reported} = 700.0\ MW$$



Apparent power (S):

Eq. (171) $$S = P_{Synch_reported} + jQ$$

$$S = 700.0\ MW + j703.6\ Mvar$$

$$S = 992.5\angle 45.1°\ MVA$$

Primary current (I_{pri}):

Eq. (172) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus_simulated}}$$

$$I_{pri} = \frac{992.5\angle -45.1°\ MVA}{1.73 \times 313.3\ kV}$$

Example Calculations: Options 15b and 16b

$$I_{pri} = 1831.2\angle -45.1° \, A$$

Secondary current (I_{sec}):

Eq. (173) $$I_{sec} = \frac{I_{pri}}{CT_{ratio_hv}}$$

$$I_{sec} = \frac{1831.2\angle -45.1° \, A}{\frac{2000}{5}}$$

$$I_{sec} = 4.578 \angle -45.1° \, A$$

To satisfy the 115% margin in Options 15b and 16b:

Eq. (174) $$I_{\text{sec}\,limit} > I_{sec} \times 115\%$$

$$I_{\text{sec}\,limit} > 4.578 \angle -45.1° \, A \times 1.15$$

$$I_{\text{sec}\,limit} > 5.265 \angle -45.1° \, A$$

Example Calculations: Option 17

Option 17 represents the calculation for Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant that is applying a phase distance relay (e.g., 21) directional toward the Transmission system. In this application it was assumed 20 Mvar of total static compensation was added.

Real Power output (P):

Eq. (175) $$P_{Asynch} = 3 \times GEN_{Asynch_nameplate} \times pf$$

$$P_{Asynch} = 3 \times 40 \, MVA \times 0.85$$

$$P_{Asynch} = 102.0 \, MW$$

Reactive Power output (Q):

Eq. (176) $$Q_{Asynch} = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

Example Calculations: Option 17

$$Q_{Asynch} = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q_{Asynch} = 83.2\ Mvar$$

Option 17, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage for the bus voltage (V_{bus}):

Eq. (177) $$V_{bus} = 1.0\ p.u. \times V_{nom}$$

$$V_{gen} = 1.0 \times 345\ kV$$

$$V_{gen} = 345.0\ kV$$

Apparent power (S):

Eq. (178) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6\angle 39.2°\ MVA$$

Primary impedance (Z_{pri}):

Eq. (179) $$Z_{pri} = \frac{V_{bus}^2}{S^*}$$

$$Z_{pri} = \frac{(345.0\ kV)^2}{131.6\angle -39.2°\ MVA}$$

$$Z_{pri} = 904.4\angle 39.2°\ \Omega$$

Secondary impedance (Z_{sec}):

Eq. (180) $$Z_{sec} = Z_{pri} \times \frac{CT_{Asynch_ratio_hv}}{PT_{ratio_hv}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times \frac{\frac{300}{5}}{\frac{2000}{1}}$$

$$Z_{sec} = 904.4\angle 39.2°\ \Omega \times 0.03$$

$$Z_{sec} = 27.13\angle 39.2°\ \Omega$$

Example Calculations: Option 17

To satisfy the 130% margin in Option 17:

Eq. (181) $$Z_{\text{sec }limit} = \frac{Z_{sec}}{130\%}$$

$$Z_{\text{sec }limit} = \frac{27.13\angle 39.2°\ \Omega}{1.30}$$

$$Z_{\text{sec }limit} = 20.869\angle 39.2°\ \Omega$$

$$\theta_{transient\ load\ angle} = 39.2°$$

Assume a Mho distance impedance relay with a maximum torque angle (MTA) set at 85°, and then the maximum allowable impedance reach is:

Eq. (182) $$Z_{max} < \frac{|Z_{\text{sec }limit}|}{\cos(\theta_{MTA} - \theta_{transient\ load\ angle})}$$

$$Z_{max} < \frac{20.869\ \Omega}{\cos(85.0° - 39.2°)}$$

$$Z_{max} < \frac{20.869\ \Omega}{0.697}$$

$$Z_{max} < 29.941\angle 85.0°\ \Omega$$

Example Calculations: Options 18 and 19

Option 18 represents the calculation for relays on Elements that connect a GSU transformer for three asynchronous generators to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Option 18 represents applying a phase time overcurrent (e.g., 51) and/or phase instantaneous overcurrent supervisory elements (e.g., 50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications installed on the high-side of the GSU transformer and remote end of the line.

Similarly, Option 19 may also be applied here for the phase directional overcurrent relays (e.g., 67) directional toward the Transmission system for Elements that connect a GSU transformer and remote end of the line to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. In this application it was assumed 20 Mvar of total static compensation was added.

Example Calculations: Options 18 and 19

Real Power output (P):

Eq. (183) $$P = 3 \times GEN_{Asych_nameplate} \times pf$$

$$P = 3 \times 40\ MVA \times 0.85$$

$$P = 102.0\ MW$$

Reactive Power output (Q):

Eq. (184) $$Q = MVAR_{static} + MVAR_{gen_static} + \left(3 \times GEN_{Asynch_nameplate} \times \sin(\cos^{-1}(pf))\right)$$

$$Q = 15\ Mvar + 5\ Mvar + (3 \times 40\ MVA \times \sin(\cos^{-1}(0.85)))$$

$$Q = 83.2\ Mvar$$

Options 18 and 19, Table 1 – Bus Voltage, calls for a 1.0 per unit of the line nominal voltage (V_{bus}):

Eq. (185) $$V_{nom} = 1.0\ p.u. \times V_{nom}$$

$$V_{bus} = 1.0 \times 345\ kV$$

$$V_{bus} = 345\ kV$$

Apparent power (S):

Eq. (186) $$S = P + jQ$$

$$S = 102.0\ MW + j83.2\ Mvar$$

$$S = 131.6 \angle 39.2°\ MVA$$

Primary current (I_{pri}):

Eq. (187) $$I_{pri} = \frac{S^*}{\sqrt{3} \times V_{bus}}$$

$$I_{pri} = \frac{131.6 \angle -39.2°\ MVA}{1.73 \times 345\ kV}$$

$$I_{pri} = 220.5 \angle -39.2° A$$

Example Calculations: Options 18 and 19

Secondary current (I_{sec}):

Eq. (188) $$I_{sec} = \frac{I_{pri}}{CT_{Asynch_ratio_hv}}$$

$$I_{sec} = \frac{220.5\angle -39.2° \, A}{\frac{300}{5}}$$

$$I_{sec} = 3.675\angle -39.2° \, A$$

To satisfy the 130% margin in Options 18 and 19:

Eq. (189) $$I_{\mathrm{sec}\,limit} > I_{sec} \times 130\%$$

$$I_{\mathrm{sec}\,limit} > 3.675\angle -39.2° \, A \times 1.30$$

$$I_{\mathrm{sec}\,limit} > 4.778\angle -39.2° \, A$$

End of calculations

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT approval, the text from the rationale text boxes was moved to this section.

Rationale for R1

Requirement R1 is a risk-based requirement that requires the responsible entity to be aware of each protective relay subject to the standard and applies an appropriate setting based on its calculations or simulation for the conditions established in Attachment 1.

The criteria established in Attachment 1 represent short-duration conditions during which generation Facilities are capable of providing system reactive resources, and for which generation Facilities have been historically recorded to disconnect, causing events to become more severe.

The term, “while maintaining reliable fault protection” in Requirement R1 describes that the responsible entity is to comply with this standard while achieving their desired protection goals. Refer to the Guidelines and Technical Basis, Introduction, for more information.

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Implementation Plan

Project 2016-04 – Modifications to PRC-025-1

Requested Approvals

- PRC-025-2 – Generator Relay Loadability

Requested Retirements

- PRC-025-1 – Generator Relay Loadability

Prerequisite Approvals

- None.

Applicable Entities*

- Generator Owner
- Transmission Owner
- Distribution Provider

*See the proposed standard for detailed applicability for functional entities and Facilities.

Terms in the NERC Glossary of Terms

- No definitions are proposed as a part of this standard.

Background

The Reliability Standard PRC-025-1 went into effect in the United States on October 1, 2014 under a phased implementation plan based on two time frames. The first timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider to apply settings to its existing load-responsive protective relays that are capable of meeting the standard while maintaining reliable fault protection. The second and extended timeframe was provided to the Generator Owner, Transmission Owner, or Distribution Provider that determined its existing load-responsive protective relays require replacement or removal. The PRC-025-1 standard drafting team recognized that it may be necessary to replace a legacy load-responsive protective relay with a modern advanced-technology relay that can be set using functions such as load encroachment or that removal of the load-responsive protective relay is the best alternative to satisfy the entity's protection criteria and meet the requirements of PRC-025-1.

General Considerations

The PRC-025-2 standard drafting team considered the scope of the proposed revisions and the timing for regulatory approvals with respect to the version one enforcement dates. The first U.S. enforcement date of October 1, 2019 applies to load-responsive protective relays where the applicable entity will be making a setting change to meet the setting criteria of the standard while maintaining reliable fault protection. The second U.S. enforcement date of October 1, 2021 applies to load-responsive protective relays where

the applicable entity will be removing or replacing the relay to meet the setting criteria of the standard while maintaining reliable fault protection.

The PRC-025-2 Implementation Plan reflects consideration of the following:

- The proposed Option 5b reduces the implementation burden to the applicable entities.
- The proposed revisions to Options 14a, 14b, 15a, 15b, 16a, 16b, 17, 18, and 19 may give reason for entities to re-evaluate their settings for load-responsive protective relays.
- A few proposed Option(s) now include the 50 element.

Effective Date

PRC-025-2

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Effective Date and Phased-In Compliance Dates

Load-responsive protective relays subject to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider shall not be required to comply with Requirement R1 until the following dates after the effective date of Reliability Standard PRC-025-2:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 12 months after the effective date of Reliability Standard PRC-025-2
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 36 months after the effective date of Reliability Standard PRC-025-2

Load-responsive protective relays which become applicable to the standard

Each Generator Owner, Transmission Owner, or Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of itself including but

not limited to changes in NERC Registration Criteria or Bulk Electric System (BES) definition, shall not be required to comply with Requirement R1 until the following dates:

Requirement	Applicability	Implementation Date
R1	Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-2 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection.	Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is not necessary, 60 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Generator Owner, Transmission Owner, or Distribution Provider that replacement or removal is necessary, 84 months beyond the date the load-responsive protective relays become applicable to the standard

Retirement Date

- PRC-025-1
  Reliability Standard PRC-025-1 shall be retired immediately prior to the effective date of PRC-025-2 in the particular jurisdiction in which the revised standard is becoming effective.

Phased-In Retirement

- None.

Implementation Plan for Definitions

- No definitions are proposed as a part of this standard.

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Violation Risk Factor and Violation Severity Level Justifications

PRC-025-2 – Generator Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-025 – Generator Relay Loadability. Note that no Requirement, Measure, or VRF/VSL changes have been made in this proposed PRC-025-2 Reliability Standard.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or

restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings
- Synchronized data recorders

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard

The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards

The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels

Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-025-2, R1	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with PRC-025-2, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 “blackout” in the northeastern North American continent.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: The blackout report and subsequent technical analysis noted that generators tripped for the conditions being addressed by this standard, increasing the severity of the blackout.
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Only one requirement is provided and is proposed for a “High” VRF.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: Requirement R1, criterion 6 of PRC-023-2 – Transmission Relay Loadability addresses similar concerns regarding Transmission lines and is also a “High” VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs: The results of the reports into the August 2003 blackout, as well as the subsequent analysis, clearly demonstrate that violating this requirement, under abnormal or emergency conditions, could cause or contribute to cascading failures on the Bulk Electric System.

VRF Justifications – PRC-025-2, R1	
Proposed VRF	**High**
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation: This requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-025-2, R1				
R1	**Lower**	**Moderate**	**High**	**Severe**
R1	N/A	N/A	N/A	The Generator Owner, Transmission Owner, or Distribution Provider did not apply settings in accordance with PRC-025-2 – Attachment 1: Relay Settings, on an applied load-responsive protective relay.
VSL Justifications – PRC-025-2, R1				
NERC VSL Guidelines				The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance				The VSL is not changing from the current approved version; therefore, there is no lowering the current level of compliance.

Proposed VSLs for PRC-025-2, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The single proposed VSL is a binary VSL (pass-fail). The entity either "applied" or "did not apply" the setting(s) in accordance with Attachment 1: Relay Settings; therefore, the VSL is proposed to be "Severe" in accordance with the criteria for binary VSLs. Guideline 2b: The proposed VSL is clear and unambiguous.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL addresses each individual instance of violations by basing the violations on failing to apply the setting(s) on "an applied load-responsive protective relay" in accordance with Attachment 1: Relay Settings.

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-003-1 – Frequency Response and Frequency Bias Setting		
Date Submitted: 2/17/2017			
SAR Requester Information			
Name:	Jerry Rust – Designated Representative For Frequency Response Sharing Group (18 BAs)		
Organization:	Frequency Response Sharing Group		
Telephone:	503.445.1074	Email:	jerry@nwpp.org
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to Existing Standard		☐ Withdrawal of Existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
There are several problems with respect to the existing Standard: • The IFRO calculation in BAL-003-1 needs to be revised due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B, the Eastern Interconnection Resource Contingency Protection Criteria, evaluation of t_0 and clarification of language in the 2016 Frequency Response Annual Analysis (FRAA) Report.

SAR Information
• The IFRO calculation in BAL-003-1 is retrospect and has no bearing on real-time reliability • Allocation of the IFRO to the BAs has no reflection of real-time situation; it is predicated on two-year old information. • The applicability to the FRSG or a BA that is not part of an FRSG is not tied to any ability to provide response, since response is either from generator or load. The BA is responsible for balancing, frequency load response is inherient to load characteristics and non controllable unless load is shed. Generator response is controllable through proper governor operation thus there is direct applicability to Generator Owners and Operators. • The arbitrary allocation formula assumes all BAs have exactly the same characteristics, such as load response, mix and type of generation, and others, which is not true, and thus is not providing comparability across all BAs. • FRM is calculated using net interchange actual which assumes all BAs have exactly the same settings for response, where one large BA could have a governor and or speed controller setting with zero deadband and set to respond at twice their allocated requirement, that may result in the apparent suppressing of the adjacent BA's response, since measurement is interchange. In addition, BAL-003-1 appears to drive an arbitrary market and pricing, thus it is not market neutral. • The FRM measurement period (20-52 seconds) is too far beyond the event to accurately measure the frequency-response provided (10-20 seconds) to arrest the frequency deviation. FRM should be measured correctly and obligated to all the correct responsible parties within an Interconnection. • The intent of the Standard is to assure adequate Frequency Response for the Interconnection. The standard should address the adequate amount of Frequency Response to arrest sudden frequency deviations within an Interconnection. The standard must be able to measure all types of Frequency Response and credit the providers. The current standards doesnot reflect different types of Frequency Response and the timing of such response.
Purpose or Goal (How does this request propose to address the problem described above?):
Revise the BAL-003-1 standard in a two phase approach First phase address: • the inconsistencies in calculation of IFROs for Interconnection Frequency Response performance changes of Point C and/or Value B; • the Eastern Interconnection Resource Contingency Protection Criteria; • the evaluation of $t_{0;}$ and,

SAR Information
• clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities. Please refer to the 2016 FRAA Report for additional information. Second phase address: • Assign the ability to control and provide Frequency Response to the correct applicable entity; • Tie Frequency Response to real-time reliability; • Eliminate arbitrary and non-comparable formulas; • Establish a process to measure Frequency Response that is not an arbritrary estimate using NetActual Interchange; • Establish a process that reflects measurement of real-time reliability associate with frequency response; • Reflect real-time topology of BES and capability and variances in types of response; • Eliminate the incorrect signals to the market for arbritray pricing and conditions; and • Develop a more correct real-time reliability standard.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
For Phase 1, please refer to the 2016 Frequency Response Annual Analysis (FRAA) Report. For Phase 2, modify the standard reflecting real-time with the correct responsible entity identified.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
For Phase 1, during the 2016 annual evaluation of the values used in the calculation of the IFRO, the above mentioned problems were identified. The scope of the work will be to (1) address the inconsistency in the CBR ratio, (2) reevaluate the Resource Contingency Protection Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12), and clarify language in the 2016 Frequency Response Annual Analysis (FRAA) Report. Please refer to the 2016 FRAA Report for additional information. For Phase 2, the FRSG has identified the above issues and the unintended consequences, without addressing real-time reliability. The scope of the work will be to (1) establish a real-time reliability standard addressing the necessary frequency response to maintain reliability, (2) establish

SAR Information
comparability for the correct responsible entity, (3) develop real-time measurements incorporating topology difference, and (4) eliminate the incorrect indicators.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
For Phase 1: • Consider revising the BAL-003-1 standard concerning #1 above through the standards development process to correct the inconsistency in the CBR ratio. The CBR ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligation to be carried, essentially penalizing improved performance. • Consider revising the BAL-003-1 standard concerning #2 above through the standards development process to modify the Resource Contingency Protection Criteria. The Resource Contingency Protection Criteria for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the "largest resource event in last 10 years", which is the 4 August 2007 event. The standard drafting team should revisit this issue for modifications to BAL-003-1 standard, and the Resources Subcommittee should recommend how the events are selected for each interconnection. • Consider revising the BAL-003-1 standard concerning #3 above through the standards development process to revisit the frequency nadir point used in the calculation. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point that exceeds the t_0 +12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding t_0+12 seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds), and may be the value known as Point C' which typically occurs from 72 to 95 seconds after t_0. • Consider revising BAL-003-1 Attachment A to provide clarity to the intent with particular attention to FRSGs and the timeline for Balancing Authority Frequency Response and Frequency Bias Setting. Please refer to the 2016 FRAA Report for additional information. For Phase 2:

SAR Information
• Consider revising BAL-003-1 standard to reflect real-time measurement of frequency performance vs. a two year old allocation. • Consider revising BAL-003-1 Standard to reflect the correct applicable entity that controls and provides frequency response. • Consider revising BAL-003-1 Standard to reflect comparability among the applicable entities. • Consider revising BAL-003-1 Standard to eliminate arbitray allocation of responsibility. • Consider revising BAL-003-1 Standard to eliminate the incorrect signals that have created unintended consequences.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.

Reliability Functions		
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Reliability and Market Interface Principles	
Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
None	

Related SARs	
SAR ID	Explanation
None	

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

Standards Authorization Request
Revision to
BAL-003-1.1 Frequency Response and Frequency Bias Setting
June 28, 2017

The North American Electric Reliability Corporation (NERC) Standard Process Manual Version 3, Section 4.0, *Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard* requires a Standard Authorization Request (SAR) that proposes to substantially revise a Reliability Standard to be accompanied by a technical justification that includes, at a minimum, a discussion of the reliability-related benefits and costs of modifying the Reliability Standard and a technical foundation document to guide the development of the Reliability Standard. North America's only registered Frequency Response Sharing Group (FRSG), consisting of 20 Balancing Authority Areas (BAAs) within the Western Interconnection (encompassing 38 BAAs in total), submitted a SAR on February 17, 2017 requesting a revision to the existing Reliability Standard BAL-003-1.1 (BAL-003). NERC has requested additional technical justification for the SAR.

This document provides further technical justification for the previously submitted SAR, organized according to the following topics:

- Real-Time Reliability
- Event Selection
- Measurement
- Assumption behind the current standard
- Goal of a Reliability Standard

Real-Time Reliability

BAL-003 states that compliance is judged according to performance for the median event out of a larger set of historical events evaluated for a particular compliance year. This suggests it is acceptable for BAAs to provide adequate frequency response just over half the time. The standard assumes a statistical probability that if one BAA fails there will be enough excess response from other BAAs to compensate. But it also follows that all BAAs could simultaneously provide insufficient frequency response on multiple occasions without any compliance failures. This fact alone indicates BAL-003 does not adequately assure real-time reliability.

Furthermore, relying on historical event analysis to establish and evaluate frequency response does not ensure frequency response is available in real-time. Frequency response is needed 24 hours a day, 365 day a year, to manage interconnection frequency and recover from frequency events. If the Interconnection were dispatched as a single system, the operator would estimate frequency response capability needed from each resource and dispatch those resources as

necessary to ensure reliability. An interconnection made up of multiple BAAs should not be treated any differently.

BAA operators must decide how to operate their systems to support reliability. BAL-003, in its current form, does not specify the amount of frequency response reserves needed in real-time for reliability—that is, capacity needed on frequency responsive resources to be prepared for the design event of an Interconnection Most Severe Single Contingency. Yet NERC's *Reliability Guideline for Operating Reserve Management* (*Guideline*) addresses this question directly. Section V.a. of the guideline states:

> *To determine an initial target (at scheduled frequency) frequency responsive reserve level (in MW) for a given responsible entity, simply multiply 10 times the responsible entity's FRO (because FRO is in MW/0.1 Hz) by the MDF for the responsible entity's Interconnection. An example to illustrate this:*
>
> *Given: ABC responsible entity is in the Eastern Interconnection (EI) and its pro-rata portion of IFRO is 1.5%.*
>
> *The key EI parameters from Table 1 are: IFRO = 1002 MW/0.1 Hz and MDF = 0.449 Hz.*
>
> *The responsible entity's FRO is {1.5% *1002 MW/0.1 Hz} or 15.2 MW/0.1 Hz.*
>
> *The responsible entity's initial frequency responsive reserve target is {10 * 15.2 * 0.449} or 67.48 MW.*
>
> *The initial target may need to be modified based on several factors, most of which are addressed later in this section. For example, if actual performance indicates additional response is needed, then the target should be increased.*

The studies performed by NERC determined the Maximum Delta Frequency A to B based on a statistical analysis of the B to C ratio. This study, in conjunction with the *Guideline*, indicates the Western Interconnection should maintain frequency responsive reserve capacity online at all times equal to approximately three times the Interconnection Frequency Response Obligation (IFRO). This amount is disputable and seems like an overestimate of reserve needed in the Western Interconnection. This is in light of The Western Interconnection's frequency response performance in recent events approximately the MW size of the double Palo-Verde design event. An overestimate or not, the current standard only obligates a BA to keep some level of this reserve available a little more than half of the year. BAL-003 must provide for this and more study needs to justify the reserves needed by BAs in real-time. Until then, the guideline provides some guidance for how much a BAA should hold in MW capacity, but the *Guideline* further states:

> *The responsible entity also may choose to perform a risk analysis in determining the level of frequency responsive reserve that assures compliance at an acceptable cost.*

This presents a problem. Reliability should not turn on economic decisions. Reliability requirements must be incorporated into standards and not just captured in guidelines that are

enforced solely by peer pressure within industry. Instead of being clear, BAL-003 sends mixed messages to BAAs.

Given the current gap in BAL-003 and the "wiggle room" in the *Guideline*, BAAs could achieve compliance in many unreliable ways. For example, a BAA could only hold enough capacity to cover a 0.1 Hz deviation, because most BAL-003 measurement events in the Western Interconnection are less than 0.1 Hz (since evaluation of FRM as currently prescribed in BAL-003-1.1 began in compliance year 2015, the average frequency deviation of all NERC selected events was only -0.060 Hz/0.10 MW). Or, a BAA could plan to meet all events in two quarters of a compliance year, and then neglect the other two quarters. A pattern that could be desirable for entities that take down generation for annual maintenance, normally in the spring in the Western Interconnection. Even if BAAs operate conscientiously to protect reliability, BAL-003 creates confusion about what is needed in real-time to support reliability.

Following FERC's order approving BAL-003, markets have developed for "paper" transactions in which one BAA can agree with another to transfer "credit" for calculated frequency response (referred to as Frequency Response Transfers). While the members of FRSG generally support allowing BAAs to comply through Frequency Response Transfers, they worry that assessing compliance according to a median-based metric could degrade real-time reliability.

For example:

> Suppose a BAA cannot fully comply with BAL-003, but has existing generation equipment that does provide some frequency response. The BAA finds itself integrating substantial variable generation that does not provide automatic frequency response. The increasing variable generation displaces frequency-responsive generating units for at least half of the operating hours. The BAA weighs its options. It could pay generators to improve equipment; it could alter dispatch to increase headroom on frequency responsive units; it could install a battery capable of frequency response; and so on. After analysis, the BAA decides it is most economic to meet its Frequency Response Obligation (FRO) entirely through Frequency Response Transfers. The BAA does not seek to improve equipment capability, and it has every right to shut down frequency-responsive units to make room for the new variable generation. Available frequency response will decline compared to historic levels. The BAA now relies entirely on the transferring BAA. In this scenario, historic frequency response is lost. The transferring BAA need only respond adequately for more than half of the compliance measurement events, and the purchasing BAA is relieved of any obligation to provide frequency response in real-time. This also flies in the face of the underlying assumption of statistical probability.

BAL-003 does not require *operational* (as opposed to paper) transfers of frequency response, and therefore has not resulted in creation of real-time markets for frequency response. NERC regulations should drive market signals that reflect what is truly needed for reliability, and ensure 100% coverage through equipment, capacity, and dispatch.

Another problem with BAL-003 is that it measures the average frequency support in the 20 to 52 seconds following a frequency event, even though machine action is needed within the first 20

seconds to arrest rapid frequency decline in the Western Interconnection. The measurement lag encourages BAAs to delay response to improve compliance metrics, which subverts the primary purpose of the standard. Western Interconnection frequency could drop low enough to trigger Underfrequency Load Shedding without a single BAA failing to comply with BAL-003. This lessens, rather than enhances, Western Interconnection reliability.

The FRSG recognizes, as do NERC and FERC, that the generation fleet is changing. Frequency response will likely decline unless operators maintain frequency-responsive capability and resources are dispatched in real-time to provide adequate headroom for frequency response. The FRSG also concurs with NERC that, historically, the Western Interconnection has had sufficient frequency response. To speak plainly, the sky is not falling and risks to reliability may not be immediate. But neither NERC nor the electric utility industry should ignore this issue. Operational requirements must be clearly stated to ensure that equipment, operations, and markets develop to support real-time reliability now and in the future.

Event Selection and Measurement:

Several aspects of BAL-003's event selection and response measurement process may perversely reward poor performance and penalize proper performance. NERC's *Reliability Guideline on Primary Frequency Control* encourages Generator Operators to set governor dead bands of no more than 36 mHz (and recommends using an even smaller dead band), with a ramped (not stepped) droop of between 4% to 5%. While a smaller dead band may be feasible in the Eastern Interconnection, frequency within the smaller Western Interconnection is more variable. Here, smaller dead bands would impose undue burdens on thermal generators. Likewise, due to the size of the Western Interconnection, credible N-1 events can drop the C and B frequency points well outside the 36 mHz dead band.

In the Western Interconnection, the generation fleet provides primary frequency response for large events through governor action. Operators have gone to significant effort, in good faith, to tune governors and associated controls according to the *Guideline* to protect reliability and comply with BAL-003. Yet the current methods of event selection and response measurement do not take these settings into account.

One deficiency is that FRO and Frequency Response Measured (FRM) derive from change in frequency instead of actual frequency. Many governors have been set (as indicated by the *Guideline*) to use a dead band of 36 mHz. Therefore any changes in frequency between 59.965 and 60.035 Hertz should not trigger frequency response, but these governors with governor droop set correctly, should respond to frequencies outside the dead band. Likewise, because the governor response is ramped starting at the edge of the dead band instead of stepped, the response for a frequency that is outside but close to the dead band should be small. Therefore a change in frequency from 60.03 to 59.97 should not result in governor response, a change from 60.00 to 59.94 should result in moderate governor response, and a change from 59.97 to 59.91 should result in substantial governor response, even though all three events have the exact same

frequency delta. Yet the FRM and FRO calculations treat these as equivalent events, penalizing BAAs for correctly respecting the NERC-defined dead band.

Another deficiency is the gap between 0 and 20 seconds in the measurement period. The first 8-12 seconds of an event are when frequency excursions are actually arrested. While this period is difficult to measure through Interchange metering, it is the critical period to prevent underfrequency load shedding. The measurement period lag (20-52 seconds) encourages BAAs to install controls with a 15 or 20 second delay in frequency response. Control equipment could operate less often without compromising compliance scores—certainly an unintended consequence, and one that could undermine the reliability of the Interconnection. This practice of delaying response to ensure compliance for the sake of economics at the expense of reliability is already being implemented on resources within the Western Interconnection as a direct result of the current BAL-003-1.1 measurement criteria.

Yet another issue with the FRM measure is its assumption that frequency response is linear. Although a linear assumption is reasonable for governor technology, even a governor can behave non-linearly. A step change response, capable in inverter based technology, drastically inflates the FRM measure within the first tenth of a Hertz. For example, a battery capable of injecting 10 MW upon sensing a frequency change would achieve a FRM of 10 MW/0.1 Hz for an A to B event of 0.1 Hz. That same battery would achieve a FRM of 100 MW/0.1 Hz for an A to B event of 10 mHz. The difference between FRM for the same MW injection within the first tenth of a Hertz is close to 90 MW/0.1 Hz while the difference one tenth and two tenths is only 5 MW/0.1 Hz. Because of the fraction on the denominator of the FRM equation, the equation becomes less variable for an A to B value of 0.1 Hz or greater. This needs to be accounted for in the BAL 003 standard.

There are additional problems with the number of events selected for compliance assessment and the median response requirement. By requiring selection of numerous events, regardless of how many significant frequency events occur, BAL-003 skews compliance evaluation toward events within the 36 mHz dead band. This penalizes proper performance as described above. Even if all frequency events within the dead band were excluded, the events selected to date (including previous year sample selections) have an average delta frequency of roughly 0.06 Hz. This means BAAs could remain compliant even if they carried only enough frequency responsive reserve to cover frequency changes of less than 0.1 Hz—far less than the Interconnection would need to prevent underfrequency load shedding in a major event (which is what BAL-003 is intended to prevent).

BAL-003 is intended to ensure the Western Interconnection has enough frequency responsive reserve to prevent underfrequency load shedding for a net loss of 2,440 MW, with a starting frequency of 59.976. As described above, a BAA that has installed generator controls to provide exactly that response using the NERC *Guidelines* will be penalized for not responding to small events (which is correct), whereas a BAA that carries just enough frequency responsive reserve to respond to much smaller events, or intentionally delays its response to optimize compliance over reliability, could be rewarded.

This means the Western Interconnection could experience multiple underfrequency load shedding events in a year without a single BAA failing the standard. Conversely, multiple BAAs could fail despite providing proper and reliable frequency response. Not only is this biased against BAAs that take action in good faith to follow NERC's *Guideline*, but over time, as BAAs migrate toward more cost-effective compliance methods, the Western Interconnection's initial frequency response, as well as total frequency response available, could decline.

Use of "Net Actual Interchange" to Measure Compliance with BAL-003, R1:

Net Actual Interchange (NI_A) is defined as the algebraic sum of all metered interchange over all interconnections between two physically adjacent BAAs. BAL-005-0.2b allows a scan rate of up to six seconds for both tie-line telemetry and automatic generation control (AGC) calculation. Using these values to calculate FRM has many inherent problems, and is ill suited to measure BAA response to frequency deviations caused by losses of large generating resources.

(1) The time frame for calculating a BAA's FRM is 20 to 52 seconds after a frequency deviation is identified in historical data provided by the BAA's energy management system (EMS). Many EMS/SCADA systems do not or cannot synchronize tie-line telemetry for calculation of Area Control Error (ACE) or FRM. Due to scan rates of telemetry equipment, this non-synchronization of tie-line data can dramatically skew the calculation of FRM. Although there is no intentional time delay in any of the telemetered data, permitted scan rates of up to six seconds can create lags of up to twelve seconds, depending on the timing of the event and the measurement transmitted to the host EMS for recording and calculation purposes. Measuring response beginning at 20 seconds after the frequency event is detected can skew a BAA's apparent FRM performance—whether for better or for worse, at random.

(2) Although most measurements for NI_A occur at physical meters on interties, many BAAs have pseudo-tie telemetry that does not originate from a physical meter. These pseudo-tie values are commonly associated with jointly owned generating facilities that may contribute significantly to a BAA's FRM. In addition to lag effects from scan rates of remote terminal unit (RTU) data, there are several other delays in receiving, calculating, and transmitting measurements used to calculate pseudo-tie values. Once a host BAA receives the core measurements to derive a preliminary pseudo-tie value, several additional computational and transmitting cycles must occur. At a minimum, the host BAA must run a calculation within its EMS or other control system, which may take up to six seconds. Once the value has been calculated, it is transmitted to neighboring BAAs that share the pseudo-tie value, typically through Inter-Control Center Communication Protocol (ICCP) data links. The ICCP transmittal is separate from the calculation process, with up to 12 seconds of latency between sending and receiving. As with the timing lag described in Item 1 above, the skewing effects of pseudo-tie measurements and calculation, with respect to BAL-003 compliance evaluation, are essentially random.

(3) When a frequency deviation occurs due to loss of a large generator, generator governors respond automatically to the resulting drop in frequency. If a BAA is electrically between a large resource providing frequency response and the lost generation, transmission flows can increase on the intermediary BAA's system. As transmission flows increase, transmission line losses increase as well. These losses appear as increased load on the intermediary BAA's system, which can in turn affect apparent FRM performance. In some instances, even though the BAA's generation and load response was appropriate, the losses incurred due to neighboring generator response can overwhelm the BAAs actual FRM.

(4) There is no accommodation for a BAA experiencing an intentional change to its NI_A. In previous years, scheduled interchange would be adjusted only within the 10 minutes ahead of or after the operating hour or during curtailments to manage rare unplanned transmission events. Frequency bias procedures allowed BAAs to ignore events that occurred during these intentional changes to Net Scheduled Interchange. With the advent of 15-minute scheduling, schedule changes can occur during 50 out of every 60 minutes of any operating hour. Furthermore, many BAA's representing a significant share of the WECC interconnection are currently operating in a joint 5-minute market, which results in intentional ramps at all times. This market continues to expand and other markets are developing, increasing the percentage of BAA's that experience constant intentional ramps due to NSI changes. If, by chance, a frequency deviation (selected for compliance evaluation) were to occur during this intentional re-dispatch, chances are 50%-50% that the BAA could be benefitted or harmed for BAL-003 compliance purposes. These intentional changes in Net Scheduled Interchange do not adversely affect reliability, but could harm BAA performance under BAL-003.

(5) BAAs often adjust internal generation in anticipation of daily load variations. During certain seasons, a BAA may experience relatively large changes in native load. The BAA may intentionally dispatch generation to prepare for these anticipated changes in native load and expected changes to hourly NI_A. Again, if by chance, a frequency deviation were to occur during this intentional re-dispatch, BAA compliance measurement could be improved or degraded, with no correlation to reliability.

(6) BAAs may also adjust internal generation to manage anticipated changes in output from Variable Energy Resources (VERs), primarily photovoltaic (PV) generating facilities. The California Independent System Operator (CAISO) has stated that as much as 47% if its BAA load has been served by VERs. Both increases and decreases to PV output occur on a daily basis. To manage these changes in anticipated VERs, a BAA will proactively ramp conventional generation or schedules. The result, if there is a concurrent frequency event used to measure BAL-003 compliance, is as descried above in Items 4 and 5.

Obligation for Generator Owners and Operators:

Frequency Response (FR) is a measure of an Interconnection's ability to arrest and stabilize frequency deviations following the sudden loss of generation or load, and is affected by the

collective responses of generation and load throughout the Interconnection. The primary FR provided the generation fleet within an Interconnection has a significant impact on the overall FR. BAL-003 specifies the amount of frequency response (per Hertz of frequency deviation) needed from BAAs to maintain Interconnection frequency within predefined bounds and includes requirements for the measurement and provision of FR. But BAL-003 contains nothing that obligates Generator Owners/Operators (GO/GOP) to provide primary frequency response. BAAs are disadvantaged under the standard, with few options beyond expensive yearly markets for frequency responsive reserve capacity products. If BAL-003 is intended to ensure a positive frequency response to frequency excursions, then GO/GOPs must be subject to the standard.

Nothing in any other NERC standard or in the provisions of the FERC *Pro Forma* Tariff or Generation Interconnection Agreement (GIA) requires GO/GOPs to provide primary frequency response. Even a generator following the NERC Reliability Guideline – Primary Frequency Control may, in many cases, fail to respond due to the lack of headroom during an event or the blocking of the governor signal in the plant control or auxiliary systems. The BAA has no way through GIAs or tariff language to require otherwise. BAL-003 allocates a portion of the IFRO to the individual BAA, which must then attempt to allocate the obligation to all generators in the BAA. In most cases, GO/GOPs have refused to run generator units to reserve headroom for frequency response. Some GO/GOPs have asked how much they need to provide. BAAs can only explain that BAL-003 requires response expressed as a MW/0.1 Hz range. This makes it difficult to define exactly what they must provide. The retrospective nature of this standard does not enable BAAs to determine future performance and or inform GO/GOPs of their forward-looking obligation.

The ERCOT BAL-001-TRE-1, R7, "Primary Frequency Response" standard obligates the GO/GOPs to maintain functional generators and to also provide frequency response during relevant events. *"Each GO shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GO has a valid reason for operating with the Governor not in service and the GOP has been notified that the Governor is not in service."* BAA obligations under ERCOT's standard are mostly reporting and tracking response from all generators.

FERC recognized the ERCOT standard for primary frequency response got it right and should be a pattern for future standards and revisions to current standards.[1] The ERCOT standard provides a useful model for changes needed to remedy the problems with BAL-003, or develop a Western Interconnection variance that recognizes how it differs from other regions in the NERC footprint.

NERC has pointed out that primary frequency response capability, by itself, would not require a resource to respond if called upon to help a BAA meet its FRO, and that, as a result, it is

[1] FERC has also accepted Regional Reliability Standard BAL-001-TRE-01 (Primary Frequency Response in the ERCOT Region) as mandatory and enforceable. *North American Electric Reliability Corporation*, 146 FERC ¶ 61,025 (2014).

important to have mechanisms to ensure that sufficient frequency response capability is not only available but ready to respond at all times. If NERC believes there are mechanisms available to the BAAs, then the standard should define those mechanisms. It is unclear how NERC could expect a BAA to meet its FRO without generator response provided by governor signals.

In its Notice of Proposed Rulemaking (NOPR) on Primary Frequency Response (Docket No. RM16-6-000), FERC stated that proposed modifications to GIAs for both large and small generating facilities (both synchronous and non-synchronous) would require new generators to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. FERC recognized that "[w]hile NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, it does not include any requirements for individual generator owners or operators," and that "[w]hen considered in aggregate, the primary frequency response provided by generators within an Interconnection has a significant impact on the overall frequency response."

The NOPR also cited a 2010 NERC survey of generator owners and operators, which found that,

> ". . . only approximately 30 percent of generators in the Eastern Interconnection provided primary frequency response, and that only approximately 10 percent of generators provided sustained primary frequency response. This suggests that many generators within the Interconnection disable or otherwise set their governors or outer-loop controls such that they provide little to no primary frequency response." (Footnotes omitted)

If FERC believes that generating facilities should be capable of providing frequency response, then the NERC standard should obligate GO/GOPs to provide it. If the generators have a significant impact on the overall frequency response, why would they be excused from BAL-003 compliance?

As noted above, NERC has approved a voluntary *Reliability Guideline on Primary Frequency Control* that encourages generators to provide a sustained and effective primary frequency response. If NERC recognized that generators were not providing primary frequency response as far back as 2010, NERC should support changes to the BAL-003 to obligate GO/GOPs to enable compliance.

There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that generators, a major source of primary frequency response, are not providing the appropriate response to frequency excursions. There is no "mechanism" available to the BAAs to compel generators to provide the necessary primary frequency response during an event. BAL-003 must be revised to address this.

Assumptions Behind the Current Standard:

BAL-003 appears to assume that all BAAs have the same composition and operate in the same manner. This may accurately describe the Eastern Interconnection. However, the Western Interconnection encompasses 38 BAAs that differ widely from one another.

Within the Western Interconnection, some BAAs are generation only, with 100% wind generation; some are generation only with 100% thermal generation; others serve load, with 100% hydro generation; and there are many other combinations.

BAL-003 rests on the assumption that as one BAA fails, the statistical probability is that other BAAs will provide sufficient excess response. But generation-only BAAs are driven by market conditions, which do not correlate to the timing of frequency events. BAL-003 allocates IFRO using a formula that has no bearing on a BAA's ability to provide frequency response. In addition, the formula uses two-year-old data to allocate IFRO. A generation-only BAA is driven by real-time conditions, not by two-year old data.

In addition, BAL-003 does a poor job of recognizing and accommodating BAA changes over time. The single largest Western Interconnection BAA (CAISO) has experienced significant changes related rooftop solar. With the installation of rooftop solar, CAISO's calculated load has decreased by over 5,000 MW, along with the reduction of the BAA calculated generation by over 5,000 MW. Under the formula to allocate IFRO, the presence of rooftop solar will reduce CAISO's FRO. At the same time, rooftop solar provides no inertia to support frequency response. Allowing large offsets from rooftop solar to reduce FRO runs counter to reliability, unfairly burdening and imposing disparate treatment on remaining BAAs. The unintended consequence is to encourage BAAs to increase the how much of their generation is behind the meter, thereby reducing their allocations of FRO. NERC's reliability standards should treat similarly situated responsible entities comparably, not create disparities among them. BAL-003 lacks flexibility to address real-time changes and real-time reliability requirements.

There is also no provision in the standard for generation that moves from one BAA to another. The BAA that lost the generation will still be held to a larger FRO than is justified by the amount of generation left in the BAA and the FRO of the attaining BAA will not change based on the increase in the amount of generation in the BAA.

Goal of a Reliability Standard

The foregoing discussion is not meant to imply that BAL-003 is completely without merit. It has brought frequency response to the forefront of many operational discussions. Some BAA operators have already taken steps to improve machine capability, change dispatch, and acquire Frequency Response Transfer from BAAs with excess. BAL-003 has moved the industry forward in its knowledge of frequency response. At the same time, it misaligns incentives for compliance and what is actually needed for reliability. This misalignment potentially drives progress in equipment, operations, and markets in the wrong direction.

To better ensure reliability, BAL-003 standard should:

- Address real-time reliability and not rely upon historical analysis and median performance. The standard needs to be flexible to address differing conditions and future changes.
- Ensure frequency response occurs to arrest rapid frequency decline and prevent underfrequency load shedding.
- Avoid unintended consequences, such as encouraging BAAs to time their response well after Point C and in the measurement period (Point B)
- Require testing of frequency responsive equipment
- Ensure comparability among all responsible entities needed for primary frequency response

SUMMARY

Real-Time Reliability

- BAL-003 as currently configured does not require response to an event. Frequency response is needed 24 hours a day, 365 day a year to manage variations in Interconnection frequency.
- Historical event-driven analysis does not ensure frequency response is available in real-time.
- Because the current standard measures historical response, and is measured by performance at the median event, the Interconnection could experience underfrequency load shedding in real-time without any compliance failures.
- The allocation of IFRO is predicated on two-year-old information, which does not reflect the Interconnection's frequency response needs in real-time.
- When a significant amount of generation trips off-line, frequency response is necessary within the first 20 seconds to arrest and stabilize rapid frequency decline. BAL-003 measures the average frequency support in the 20 to 52 second period following the event, which encourages BAAs to delay response to improve compliance. This subverts the primary purpose of the standard, and could drive less real-time reliability, not more.

Event Selection

- Current BAL-003 is driven by historical analysis of selected events and the selection criteria does not always measure frequency response. Performance metrics should reflect dead bands, beginning frequency, size and type of events, an adequate number of events, and most importantly time of measurements.
- Frequency response is mechanically driven, and can be accurately measured only during machine movement.

Measurement

- The current standard uses Net Interchange Actual (NI_A) to measure compliance. To have good measurement, one must have good statistics to support the values measured.

- NI_A is made up of several variables, changes in load, changes in generation, changes in purchases, pseudo-tie values, changes in transmission flows and losses, frequency response, and others. Statistical analysis can support measurement only when all inputs can be determined to isolate the value being measured for compliance. NI_A has far too many variables, all changing at the same time, to be treated as the sole measure of frequency response.
- Dynamic schedules are not included in the measurement, even though they may have a response component.
- Battery insertion or other responsive measures can be timed to occur in the measurement period thereby missing the arrestment period and subverting the purpose of the standard.
- Frequency response is not linear thus distorting the FRM measure, especially for events with an A to B measure less than 0.1 Hz

Assumptions Behind Current Standard

- BAL-003 appears to assume that all BAAs have the same composition and operate in the same manner. This may accurately describe the Eastern Interconnection. However, the Western Interconnection encompasses 38 BAAs that differ widely from one another.
- 100% generation only, wind only, 100% hydro base, 100% thermal base, many different mixtures
- The standard fails to recognize the changes associated with solar, and impacts associated with behind-the-meter solar. The allocation formula rewards a BAA with behind-the-meter solar and places the burden of frequency response on the remaining BAAs.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards. Please use this form to submit your request to propose a new or a revision to a NERC Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	PER-003-1 Operating Personnel Credentials and PER-004-2 Reliability Coordination — Staffing		
Date Submitted:	TBD		
SAR Requester Information			
Name:	Patti Metro		
Organization:	Chair - Project 2016-EPR-01 PER		
Telephone:	(703) 907-5817	Email:	patti.metro@nreca.coop
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
Need to add clarity to PER-003-1 that explains that the NERC certifications identified in this standard are described in the NERC System Operator Certification Program. The requirements of PER-004-2 are duplicative with requirements in several other standards that explain in detail the staffing requirements of personnel conducting the Reliability Coordinator function.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. The Project 2016-EPR-01 PER Team recommends that PER-004-2 be retired.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
N/A
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Project 2016-EPR-01 PER team recommends that a clarifying footnote be added to PER-003-1 Requirement R1, R2 and R3 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program. The PER-004-2 standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements. Specifically, PER-004-2's requirements are duplicated in standards: • PER-003-1, R1 • PER-005-2, R2 and R3 • IRO-002-4, R3 and R4 • EOP-004-2, R2 • IRO-008-2, R1, R2, and R4 • IRO-009-2, R1 – R4 • IRO-010-2, R1 – R3 • IRO-014-3, generally • IRO-018-1, R1-R3

SAR Information
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 Requirements R1, R2 and R3 to ensure that stakeholders (now and in the future) understand the connection between the Standard and the Program Manual. The PRT suggests for consideration the following language be used for the footnote "The certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program." Concerning PER-004-2, the standards is duplicative and all requirements are covered in other reliability standards. Specifically, PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks. Moreover, in PER-004-2 R1, 24 hours per day, and seven days a week requirements are addressed by several NERC Reliability Standards and Requirements. These requirements cannot be accomplished without an entity having a 24/7 operation. IRO-002-4 R4 (enforceable 4/1/2017) requires that, "Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel…" In addition, IRO-002-4 R3 states that, "Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordination Area." EOP-004-2 covers continuous observation through its reporting timeframes to meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, "Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address …(SOL) and (IROL) exceedances…" and R4 states, "Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes." Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator's maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, "Present time as opposed to future times," while Real-time Assessment is defined as "An examination of existing and expected system

SAR Information
conditions, conducted by collecting and reviewing immediately available data." Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards. PER-004-2 Requirement R2 is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3 and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times. IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits. IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to: • assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area, • ensure that coordinated plans are developed for the next-day operations to address these exceedances, and • execute Real-time Assessments at least once every 30 minutes. To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs. IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments. IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments

SAR Information
and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance. IRO-014-3 ensures that each Reliability Coordinator's operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance. IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.

Reliability Functions		
☐	Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.

Reliability and Market Interface Principles	
☒	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	YES
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	YES
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	YES
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	YES

Related Standards	
Standard No.	Explanation

Related SARs	
SAR ID	Explanation
	N/A

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	N/A
FRCC	N/A
MRO	N/A
NPCC	N/A
RFC	N/A
SERC	N/A
SPP	N/A
WECC	N/A

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Template: PER-003-1 Operating Personnel Credentials

December 2016

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee for periodic reviews, and a stakeholder Subject Matter Expert (SME) team.[2] Consistent with Section 13 of the Standards Processes Manual, the Standards Committee may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.
Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

	Standing Review Team	**Plus Section 13 (SMEs):**
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • Standards Committee (Also, the SC chair or his/her delegate from the	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] Other reliability standards included as part of the Review Team's periodic review were PER-004-2 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).

[3] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

	SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).

[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

Applicable Reliability Standard: PER-003-1
Team Members (include name and organization): 1. Patti Metro, Nation Rural Electric Cooperative Association 2. Lauri Jones, Pacific Gas and Electric Company 3. Heather Morgan, EDP Renewables North America LLC 4. Jeffrey Sunvick, Western Area Power Administration 5. Jimmy Womack, Southwest Power Pool 6. Brad Perrett, Minnesota Power 7. Carolyn White Wilson, Duke Energy Corporation 8. Michael B. Hoke, PJM Interconnection LLC 9. Danny W. Johnson, Xcel Energy 10. Darrel Richardson, NERC Senior Standards Developer 11. Candice Castaneda, NERC Counsel 12. Michael Brytowski, Great River Energy PMOS Representative
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (*If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes

   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes

☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☐ No

Please explain:

Questions for the Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

   ☐ Yes

   ☒ No

   Please summarize your application of Paragraph 81 Criteria, if any:

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

☒ Yes

☐ No

Please summarize your assessment: Although the response to the parent question above is "No" examination of its subparts (a) – (g) has led the Review Team to recommend a clarifying revision. The Project 2016-EPR-01 PER Review Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) the connection between the Standard and the NERC System Operator Certification Program Manual; and (ii) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines?

☒ Yes

☐ No

If you answered "No," please identify which elements require revision, and why:

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

☐ Yes

☒ No

If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes

      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes

      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **N/A to this standard.**

   ☐ Yes

   ☐ No

   Guiding Questions:

   a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or

Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results Based Standard:** Is the Reliability Standard drafted as a results-based standard?

☒ Yes

☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes

☐ No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?

☐ Yes

☒ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes

☐ No

II. Content

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

    ☐ Yes

    ☒ No

    If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

    ☐ Yes

    ☒ No

    If a gap is identified, please explain:

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

    ☒ Yes

    ☐ No

    If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes

☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes

☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow –is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

Preliminary Recommendation posted for industry comment (date): January 10, 2017

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☒ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☐ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

The Project 2016-EPR-01 PER Team recommends that a clarifying footnote be added to PER-003-1 to ensure that stakeholders (now and in the future) understand (i) that the certifications referenced under PER-003-1 are those under the NERC System Operator Certification Program; and (ii) the connection between the Standard and the Program Manual.

Date submitted to Standards Committee: June 14, 2017

Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[7] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[7] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber-attacks. (*footnote omitted*)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Attachment 3: Independent Expert Evaluation Process

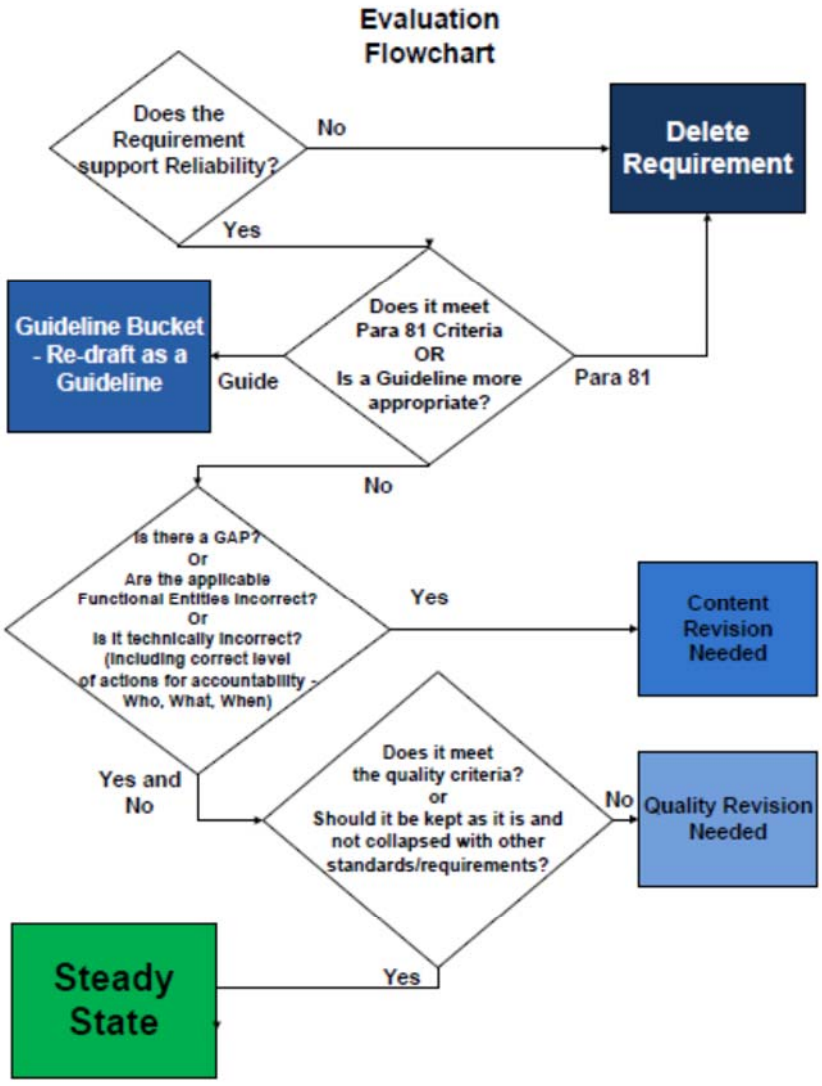

Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Template: PER-004-2 Reliability Coordination - Staffing

December 2016

Introduction

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every ten (10) years, or once every five (5) years for Reliability Standards approved by the American National Standards Institute as an American National Standard.[1] The Reliability Standard identified above has been included in the current cycle of periodic reviews. The Review Team shall consist of two (2) subgroups; a Standing Review Team which is appointed annually by the Standards Committee for periodic reviews, and a stakeholder Subject Matter Expert (SME) team.[2] Consistent with Section 13 of the Standards Processes Manual, the Standards Committee may use a public nomination process to appoint the stakeholder SME team, or may use another method to appoint that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. The technical experts provide the subject matter expertise and guide the development of the technical aspects of the periodic review, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the periodic review.
Together, the Standing Review Team and SME stakeholder team are the Review Team for a particular periodic review project and complete their portion of the template below.

The purpose of the template is to collect background information, pose questions to guide a comprehensive review of the Standard(s) by the Review Team, and document the Review Team's considerations and recommendations. The Review Team will post the completed template containing its recommendations for information and stakeholder input as required by Section 13 of the NERC Standard Processes Manual.

Review Team Composition

	Standing Review Team	**Plus Section 13 (SMEs):**
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • Standards Committee (Also, the SC chair or his/her delegate from the	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] Other reliability standards included as part of the Review Team's periodic review were PER-003-1 (included in a separate, concurrent, report) and PER-001-0.2 (which was approved for retirement on March 31, 2017 and therefore not included in either report).

[3] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

	SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	Standing Review Team to conduct its review of the standard(s) and complete the template below.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • Standards Committee (Also, the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The Standards Committee will appoint stakeholder subject matter experts for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to conduct its review of the standard(s) and complete the template below.

The Review Team will use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation from one of the following three (3) choices:

1. Recommend reaffirming the Standard as steady-state (Green); or
2. Recommend that the standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If the team recommends a revision to or a retirement of the Reliability Standard, it must also submit a Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to Darrel Richardson at darrel.richardson@nerc.net.

[4] The Standards Committee chair may delegate one member of the SC to chair one Standing Review Team's review of a standard s), and another SC member to chair a review of another standard(s).

[5] Each committee chair may, at his or her discretion, delegate participation on the Standing Review Team to another member of his or her committee.

Applicable Reliability Standard: PER-004-2
Team Members (include name and organization): 1. Patti Metro, Nation Rural Electric Cooperative Association 2. Lauri Jones, Pacific Gas and Electric Company 3. Heather Morgan, EDP Renewables North America LLC 4. Jeffrey Sunvick, Western Area Power Administration 5. Jimmy Womack, Southwest Power Pool 6. Brad Perrett, Minnesota Power 7. Carolyn White Wilson, Duke Energy Corporation 8. Michael B. Hoke, PJM Interconnection LLC 9. Danny W. Johnson, Xcel Energy 10. Darrel Richardson, NERC Senior Standards Developer 11. Candice Castaneda, NERC Counsel 12. Michael Brytowski, Great River Energy PMOS Representative
Date Review Completed:

Background Information *(to be completed initially by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission (FERC) directives associated with the Reliability Standard? (*If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)*

   ☐ Yes

   ☒ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Interpretation or Compliance Application Notice (CAN)? (*If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or other stakeholder-identified issue(s) that apply to the Reliability Standard*.)

   ☐ Yes

   ☒ No

   Please explain:

3. Is the Reliability Standard one of the most violated Reliability Standards?

☐ Yes

☒ No

If so, does the cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☐ No

Please explain:

Questions for the Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above. Either as a guide to help answer the ensuing questions or as a final check, the Review Team is to use Attachment 3: Independent Expert Evaluation Process.

I. Quality

1. **Reliability Need, Paragraph 81:** Do any of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? *Use Attachment 2: Paragraph 81 Criteria to make this determination.*

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   This standard falls within Paragraph 81 Criterion B7, because all of its requirements are redundant with requirements in other FERC-approved reliability standards that are in effect or soon to be effective. It is not necessary or efficient to maintain such duplicative requirements and PER-004-2 may be retired with little to no effect on reliability. Specifically, PER-004-2's requirements are duplicated in standards:

   - PER-003-1, R1
   - PER-005-2, R2 and R3
   - IRO-002-4, R3 and R4
   - EOP-004-2, R2
   - IRO-008-2, R1, R2, and R4
   - IRO-009-2, R1 – R4

- IRO-010-2, R1 – R3
- IRO-014-3, generally
- IRO-018-1, R1-R3

Please refer to Page 10 of this document for a detailed justification for retirement of these requirements.

2. **Clarity:** From the Background Information section of this template, has the Reliability Standard been the subject of an Interpretation, CAN or issue associated with it, or is frequently violated because of ambiguity?
   a. Does the Reliability Standard have obviously ambiguous language?
   b. Does the Reliability Standard have language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?
   d. Should the requirements stand alone as is, or should they be consolidated with other standards?
   e. Is the Reliability Standard complete and self-contained?
   f. Does the Reliability Standard use consistent terminology?

   ☐ Yes

   ☒ No

   Please summarize your assessment:

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

   ☐ Yes

   ☒ No

   Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, Violation Risk Factors (VRF), Violation Severity Levels (VSL) and Time Horizons) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines?

   ☒ Yes

   ☐ No

   If you answered "No," please identify which elements require revision, and why:

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions or other factors?

   ☐ Yes

   ☒ No

   If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

7. **Practicable**:
   a. Can the Reliability Standard be practically implemented?

      ☒ Yes

      ☐ No

   b. Is there a concern that it is not cost effective as drafted?

      ☐ Yes

      ☒ No

   Please summarize your assessment of the practicability of the standard:

8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for generator interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard? **Not Applicable.**

   ☐ Yes

   ☐ No

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners and/or Generator Operators, is there any ambiguity about the inclusion of generator Interconnection Facilities? (If generation Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

b. If the Reliability Standard is not applicable to Generator Owners and/or Generator Operators, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, Generator Owners that own and/or Generator Operators that operate relevant generator Interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators and/or Distribution Providers, is there any ambiguity about the inclusion of Transmission Interconnection Facilities? (If Transmission Interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

9. **Results Based Standard:** Is the Reliability Standard drafted as a results-based standard?

☒ Yes

☐ No

If not, please summarize your assessment:

Guiding Questions:

a. Does the Reliability Standard address performance, risk (prevention) and capability?

☒ Yes

☐ No

b. Does the Reliability Standard follow the RBS format (for example, Requirement and Part structure) in Attachment 1?

☒ Yes

☐ No

c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?

☒ Yes

☐ No

II. Content

10. **Technical accuracy:** Is the content of the Requirements technically correct, including identifying who does what and when?

☒ Yes

☐ No

If not, please summarize your assessment:

11. **Functional Model:** Are the correct functional entities assigned to perform the requirements, consistent with the Functional Model?

☒ Yes

☐ No

If not, please summarize your assessment:

12. **Applicability:** Is there a technical justification for revising the applicability of the Reliability Standard, or specific requirements within the standard, to account for differences in reliability risk?

☐ Yes

☒ No

If so, please summarize your assessment:

13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

[6] Ten Benchmarks of an Excellent Reliability Standard, posted at Page 626 of: http://www.nerc.com/pa/Stand/Resources/Documents/DT_Reference_Manual_Resource_Package_080114.pdf

☐ Yes

☒ No

If a gap is identified, please explain:

14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

☒ Yes

☐ No

If not, please summarize your assessment:

15. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**

☒ Yes

☐ No

If not, please summarize your assessment:

16. **Related Regional Reliability Standards**: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired, appended into the continent-wide standard, or revised in favor of a continent-wide Standard?

☐ Yes

☒ No

If yes, please identify the regional standard(s) and summarize your assessment:

RED, YELLOW GREEN GRADING

Using the questions above, the Review Team shall come to a consensus on whether the Reliability Standard is Green – i.e., affirm as steady-state; Yellow –is sufficient to protect reliability and meet the reliability objective of the standard, however, there may be future opportunity to improve a non-substantive or insignificant quality and content issue – i.e., continue to monitor; or Red - either retire or needs revision, and, thus, a SAR should be developed to process the Standard through the Standards development process for retirement or revision. The reasons for the Review Team's conclusions of Green, Yellow, or Red shall be documented. If a consensus is not reached within the Review Team, minority reviews shall be posted for stakeholder comment, along with the majority opinion on whether the Reliability Standard is Green, Yellow or Red.

Recommendation

The answers to the questions above, along with its Red, Yellow, Green grading and the recommendation of the Review Team, will be posted for a 45-day comment period, and the comments publicly posted. The Review Team will review the comments to evaluate whether to modify its initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☒ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

PER-004-2 R1 is duplicative and all requirements are covered in other reliability standards. Specifically, PER-003-1 R1 states that each Reliability Coordinator shall staff its Real-time operating positions with System Operators who have obtained and maintained a valid NERC Reliability Operator certificate. PER-005-2 R1 states that each Reliability Coordinator shall design, develop and deliver training to its System Operators based on a list of Bulk Electric System (BES) company specific Real-time reliability-related tasks. Additionally, PER-005-2 R3 states that Reliability Coordinators have to verify that their personnel are capable of performing each of those tasks.

Moreover, in PER-004-2 R1, 24 hours per day, and seven days a week requirements are addressed by several NERC Reliability Standards and Requirements. These requirements cannot be accomplished without an entity having a 24/7 operation. IRO-002-4 R4 (enforceable 4/1/2017) requires that, "Each Reliability Coordinator shall have monitoring systems that provide information utilized by the Reliability Coordinator's operating personnel…" In addition, IRO-002-4 R3 states that, "Each Reliability Coordinator shall monitor Facilities, the status of Special Protection Systems, and non-BES facilities identified as necessary by the Reliability Coordinator, within its Reliability Coordinator Area and neighboring Reliability Coordinator Areas to identify any System Operating Limit exceedances and to determine any Interconnection Reliability Operating Limit exceedances within its Reliability Coordination Area." EOP-004-2 covers continuous observation through its reporting timeframes to

meet OE-417 for Loss of Monitoring. Additional coverage is ensured through IRO 008-2 R2, "Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address …(SOL) and (IROL) exceedances…" and R4 states, "Each Reliability Coordinator shall ensure that a Real-time Assessment is performed at least once every 30 minutes." Reinforcing the structure of the 24 hours per day, and seven days per week requirement is carried out by IRO-010-2 R1, requiring that Reliability Coordinator's maintain documented specifications for the data to perform Operational Planning analyses, Real-time monitoring, and Real-time Assessments. Real-time is defined as, "Present time as opposed to future times," while Real-time Assessment is defined as "An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data." Using these definitions in the Reliability Standards further confirms that PER-004-2 Requirement 1 is duplicative and non-essential as its content is covered in multiple Reliability Standards.

PER-004-2 Requirement R2 is duplicated in numerous Reliability Standards justifying the need for retirement of this requirement. As described below, the Standards and requirements of IRO-002-4, IRO-008-2, IRO-009-2, IRO-010-2, IRO-014-3 and IRO-018-1 adequately ensure that protocols are in place to allow the Reliability Coordinator operating personnel to have the best available information at all times.

IRO-002-4, R3 states that the Reliability Coordinator shall monitor Facilities and work with neighboring Reliability Coordinator areas to identify SOL and IROL exceedances within its area. In order to ensure compliance with this Standard and Requirement, particular attention must be placed on SOLs, IROLs, and inter-tie facility limits.

IRO-008-2 ensures that the Reliability Coordinator performs analyses and assessments to prevent instability, uncontrolled separation, or cascading. R1, R2, and R4 of this Standard specifically require that an Operational Planning Analysis is performed to:

- assess whether the planned operations for the next-day will exceed SOLs and IROLs within its Wide Area,
- ensure that coordinated plans are developed for the next-day operations to address these exceedances, and
- execute Real-time Assessments at least once every 30 minutes.

To maintain compliance with the IRO-008-2 Standard, the Reliability Coordinator must place particular attention on SOLs and IROLs.

IRO-009-2 builds on IRO-008-2 by ensuring prompt action to prevent or mitigate instances where IROLs are exceeded. Through the Requirements of this Standard, assurances are made that the Reliability Coordinator has one or more Operating Processes, Procedures, or Plans that identify actions to take, or

actions to direct others to take, to mitigate the magnitude and duration of an IROL exceedance identified in their Assessments.

IRO-010-2 provides data specifications that affords the Reliability Coordinator the specific data necessary to perform its Operational Planning Analyses, Real-time monitoring, Real-time Assessments and ensures that a protocol exists to resolve any data conflicts. This Standard ensures that the Reliability Coordinator has the best available information at all times to maintain compliance.

IRO-014-3 ensures that each Reliability Coordinator's operations are coordinated so that they will not adversely impact other Reliability Coordinator Areas and preserve the reliability benefits of interconnected operations. This Standard again builds on the coordination of the Operational Analyses and Real-time Assessments which requires the Reliability Coordinator to have the best available information at all times to maintain compliance.

IRO-018-1 established three requirements for Real-time monitoring and analysis capabilities to support reliable operations. Real-time monitoring involves observing operating status and operating values in Real-time to ensure awareness of system conditions. Through this Standard, processes and procedures are established for evaluating the quality of Real-time data and to provide assurance that any action taken addresses any data quality issues so that Real-time monitoring and Real-time Assessments performed by the Reliability Coordinator contains the best available information at all times.

Preliminary Recommendation posted for industry comment (date): January 10, 2017

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ REAFFIRM *(This should be checked only if there are no outstanding directives, interpretations or issues identified by stakeholders.) GREEN*

☐ REVISE *(The standard is sufficient to protect reliability and meet the reliability objective of the standard, however there may be future opportunity to improve a non-substantive or insignificant quality and content issue.)* (Would include revision of associated RSAW.) *YELLOW*

☐ REVISE *(The recommended revisions are required to support reliability.)* (Would include revision of associated RSAW.) *RED*

☒ RETIRE (Would include revision of associated RSAW.) *RED*

Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR must be included and the technical justification included in the SAR)*:

See justification above.

Date submitted to Standards Committee: June 14, 2017

Attachment 1: Results-Based Standards

Question 9 for the Review Team asks if the Reliability Standard is results-based. The information below will be used by the Review Team in making this determination.

Transitioning the current body of standards into a clear, concise, and effective body will require a comprehensive application of the RBS concept. RBS concepts employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures, and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

Accordingly, the Review Team shall consider whether the Reliability Standard contains results-based requirements with sufficient clarity to hold entities accountable without being overly prescriptive as to how a specific reliability outcome is to be achieved. The RBS concept, properly applied, addresses the clarity and effectiveness aspects of a standard.

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber-attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff and the Review Team should recommend that the Reliability Standard be revised or reformatted in accordance with the RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[7] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Periodic Review Template.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion); and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[7] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect reliability of the bulk power system.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the periodic review. The exception would be a requirement, such as the Critical Information Protection (CIP) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber-attacks. (*footnote omitted*)

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Attachment 3: Independent Expert Evaluation Process

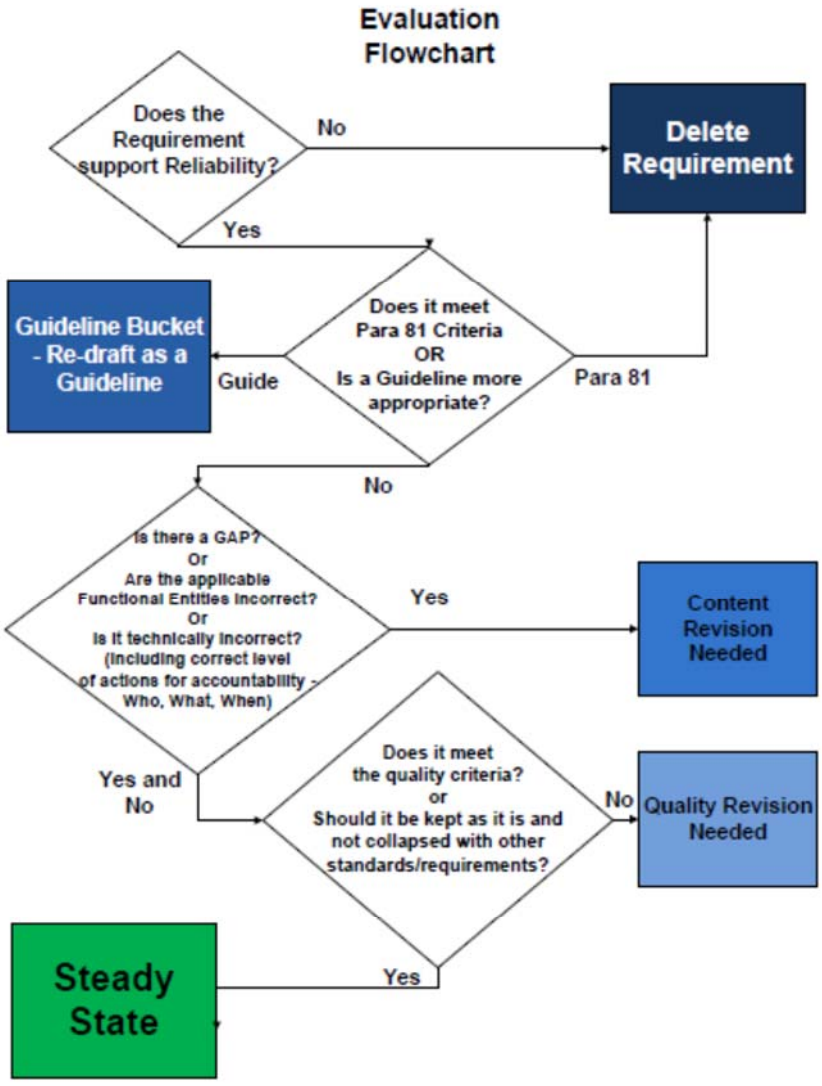

Figure 1: Evaluation Flow Chart

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Standards Announcement

Project 2017-03 FAC-008-3 Periodic Review

Periodic Review Team Nomination Period Open through May 23, 2017

Now Available

Nominations are being sought for review team members through **8 p.m. Eastern, Tuesday, May 23, 2017**.

Use the electronic form to submit a nomination. If you experience any difficulties using the electronic form, contact Nasheema Santos. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

The time commitment for this project is expected to be two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team in July 2017. Nominees will be notified shortly after they have been appointed.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Al McMeekin (via email) or at (404) 446-9675.

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Standards Announcement

Project 2017-04 Periodic Review of Interchange Scheduling and Coordination Standards

Periodic Review Team Nomination Period Open through May 15, 2017

Now Available

Nominations are being sought for periodic review team members through **8 p.m. Eastern, Monday, May 15, 2017**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the Drafting Team Vacancies page and the project page.

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and unofficial nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team July 2017. Nominees will be notified shortly after they have been appointed**.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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Standards Announcement

Project 2017-05 NUC-001-3 Periodic Review

Periodic Review Team Nomination Period Open through Tuesday, May 23, 2017

Now Available

Nominations are being sought for review team members through **8 p.m. Eastern, Tuesday, May 23, 2017.**

Use the electronic form to submit a nomination. If you experience any difficulties using the electronic form, contact Nasheema Santos An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Periodic Review team members should expect to invest an average of approximately 10 hours per month for approximately 12 months to support this project. The first face-to-face meeting is tentatively planned for August 2017 in Atlanta, with one additional face-to-face meeting in North America, in addition to regular conference calls. Team members may also have supporting projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the Periodic Review effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

Previous team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team in July 2017. Nominees will be notified shortly after they have been appointed**.**

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Mat Bunch (via email) or at (404) 446-9785.

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Unofficial Nomination Form

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Wednesday, August 9, 2017.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the Project 2017-06 Modifications to BAL-002-2 page. If you have questions, contact Senior Standards Developer Darrel Richardson, (via email), or at (609) 613-1848.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or periodic review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2017-06 Modifications to BAL-002-2

The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative."

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise in one or more of the following areas: Reliability Coordinator operations, transmission operations, Balancing Authority operations and generation operations. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Standards affected: BAL-002-2

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):	
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):	
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):	

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ Texas RE	☐ NPCC	☐ SPP RE
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standard Authorization Request (SAR) Form

Complete and please email this form, with attachment(s) to: sarcomm@nerc.net

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	Standards Alignment with Registration		
Date Submitted:			
SAR Requester			
Name:	NERC Standards Staff		
Organization:	NERC		
Telephone:		Email:	
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☒ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☐ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project will align the standards that are impacted by the Risk-Based Registration (RBR) initiative.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project aligns Standards with the FERC-approved RBR initiative.			
Project Scope (Define the parameters of the proposed project):			
This project will review and align standards impacted by the RBR initiative.			
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):			
This project will formally address any remaining edits to the standards that are needed to align the existing standards with the RBR initiatives. The edits include updates to the BAL, CIP, FAC, INT, IRO, MOD, NUC, and TOP family of standards to remove the references to Purchasing-Selling Entities (PSEs) and Interchange Authorities (IAs); references to the Load-Serving Entity (LSEs) will be replaced by either the Distribution Provider (DP) or the Balancing Authority (BA). Additionally, PRC-005 will replace the distribution provider with the Underfrequency Load Shedding (UFLS)-only DPs.			

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
The clean-up effort of the standards can be categorized into the following: 1. Modifications to existing standards where the removal of the retired function may need replacement by another function. Specifically, Reliability Standard MOD-032-1 specifies certain data from LSEs that may need to be provided by other functional entities going forward. A SAR has been submitted to modify the MOD standards, and it would be posted with the Alignment with Registration SAR. 2. Modifications where the applicable entity and references may be removed. These updates may be able to follow a similar process to the Paragraph 81 initiatives where standards are redlined and posted for industry comment and ballot. A majority of the edits would simply remove deregistered functional entities and their applicable requirements/references. The impacted standards include the BAL, CIP, IRO, and TOP family of standards. Additionally PRC-005 will be updated to replace distribution providers with the more-limited UFLS-only DP to align with the post-RBR registration impacts. 3. Initiatives that can address RBR updates through the periodic review process. This would include the INT-004 and NUC-001 standards. In other words, rather than making the revisions immediately, this information would be provided to the periodic review teams currently reviewing INT-004 and NUC-001 so that any changes resulting from those periodic reviews, if any, may be proposed at the same time after completion of each periodic review.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
No additional costs outside of the time and resources needed to serve on the SAR and SC team.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
NA
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Since LSE is being replaced by either a Distribution Provider or Balancing Authority for the standards that need to be updated, those entities will like be best suited for the MOD and PRC updates.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
NA
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
A separate SAR on the MOD standards was recently received that would be addressed by this project.
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
☐	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January X, 2017	Standards Information Staff	Revised

Standard Authorization Request (SAR) Form

Complete and please email this form, with attachment(s) to: sarcomm@nerc.com

The North American Electric Reliability Corporation (NERC) welcomes suggestions to improve the reliability of the bulk power system through improved Reliability Standards.

Requested information			
SAR Title:	MOD-032-1 Entity Change Due to Rules of Procedure Modification		
Date Submitted:	06/15/2017		
SAR Requester			
Name:	Rich Hydzik on behalf of NERC Essential Reliability Resources Work Group		
Organization:	NERC ERSWG / Avista		
Telephone:	509 495 4005	Email:	rich.hydzik@avistacorp.com
SAR Type (Check as many as apply)			
☐ New Standard ■ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ■ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
This project is intended to facilitate accurate data collection to facilitate modeling of the Distribution Provider's (DP) facilities.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Accurate modeling of distribution facilities is required to ensure that power system models accurately reflect the bulk power system (BPS) performance. These models are used in system analysis for planning purposes and construction of a reliable BPS. These models are in used in system analysis for operating purposes to ensure a reliable BPS in both short term, day-ahead, and real-time operational planning analyses.			
Project Scope (Define the parameters of the proposed project):			
This project proposes removing the Load Serving Entity (LSE) from the Applicability Section (4.1.3) and replacing LSE with Distribution Provider (DP) as the applicable entity for Section 4.1.3. LSE is no longer considered a reliability entity due to a change in the NERC Rules of Procedure. The DP is defined as "provides and operates the 'wires' between the transmission system and the end use customer." The DP is the applicable entity to provide data for power system modeling and analysis for distribution systems. Attachment 1 should be modified by replacing the applicable entity LSE with DP.			

Requested information
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1]which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.* research paper) to guide development of the Standard or definition):
This project proposes removing the Load Serving Entity (LSE) from the Applicability Section (4.1.3) and replacing LSE with Distribution Provider (DP) as the applicable entity for Section 4.1.3. LSE is no longer considered a reliability entity due to a change in the NERC Rules of Procedure. The DP is defined as "provides and operates the 'wires' between the transmission system and the end use customer." The DP is the applicable entity to provide data for power system modeling and analysis for distribution systems.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impacts should be minimal. Planning Coordinator and Transmission Planners are required to collect modeling data under MOD-032-1. In the past, Planning Coordinator and Transmission Planners collected from LSE's. This entity would be the DP under the proposed change.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*. Dispersed Generation Resources):
None
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g*. Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Planning Coordinator Transmission Planner Transmission Operator Distribution Provider
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
No
Are there any related standards or SARs that should be assessed for impact as a result of this proposed project? If so which standard(s) or project number(s)?
No
Are there alternatives (e.g. guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives. None identified

Reliability Principles	
Does this proposed standard development project support at least one of the following Reliability Principles (Reliability Interface Principles)? Please check all those that apply.	
■	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
■	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	yes

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g. NPCC	

For Use by NERC Only

SAR Status Tracking (Check off as appropriate)	
☐ Draft SAR reviewed by NERC Staff ☐ Draft SAR presented to SC for acceptance ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions to the NERC Standard Processes Manual

Appendix 3A to the NERC Rules of Procedure

Revisions are proposed to Sections 2.1, 3.7, 6.0, 7.0, 8.0, and 11.0 of the NERC Standard Processes Manual (SPM), Appendix 3A to the NERC Rules of Procedure.

A redline of the proposed revisions is available on the Revisions to the NERC SPM page.

The proposed revisions are posted for a 45-day formal comment period from March 20, 2017 through May 3, 2017. An initial ballot will be conducted from April 24, 2017 – May 3, 2017. All comments should be submitted through the NERC Standards Balloting and Commenting System (SBS).

Background Information

Under the oversight of the NERC Standards Committee (SC), a small group consisting of Standards Committee Process Subcommittee (SCPS) members and NERC staff have reviewed specific sections of the NERC SPM for the purpose of proposing revisions to clarify and improve existing language and processes. Below is a summary of the revisions, which have been endorsed by the SCPS and the SC and are posted for ballot and comment.

Section 6.0 - Process for Conducting Field Tests

In March 2015, the SC endorsed developing draft revisions to the SC Charter and Section 6 of the SPM to develop more concise language and provide NERC's technical committees with additional oversight and authority over the technical aspect of field tests associated with Standards Authorization Requests and standards projects. NERC staff, along with members of the NERC Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee, worked together to develop the proposed revisions. The revisions were posted for informal comment from September 29, 2015 through October 28, 2015. In response to comments, revisions were made to clarify roles, responsibilities, and process steps.

Section 6.1 is revised to streamline the requirements for field tests to validate concepts that support the development of requirements (current Section 6.1) and field tests of technical concepts in a proposed new or revised Reliability Standard (current Section 6.2). Three new subsections are created:

> Proposed Section 6.1.1 summarizes the requirements for seeking approval of a field test. Under the proposed revisions, the requesting team must first identify a NERC technical committee to lead the effort to conduct the field test and seek approval from that technical committee to conduct the field test before seeking SC approval. The technical committee shall provide the SC with a recommendation regarding approval.

Proposed Section 6.1.2 provides that the lead NERC technical committee overseeing the field test may stop or modify the field test if it determines that the field test activity poses a reliability risk to the Bulk Power System. Prior to restarting a stopped field test, the requesting team must receive approval from the lead NERC technical committee and the SC in accordance with proposed Section 6.1.1.

Proposed Section 6.1.3 describes that a field test may be continued, modified, or terminated in the event a conclusion cannot be formulated within the time allotted in the field test plan, subject to the approval of the lead technical committee overseeing the field test.

Proposed Section 6.2 clarifies the processes governing communication and coordination for field tests. The proposed revisions clarify the process for seeking, approving, and making notifications with respect to compliance waivers for participating entities unable to comply with currently-enforceable Reliability Standards due to their participation in the field test. Proposed Section 6.2 also contains requirements for reporting on field test progress and results, including requirements to keep the NERC Board of Trustees informed regarding new and ongoing field tests and any requested compliance waivers.

Section 7.0 - Process for Developing an Interpretation

Revisions are proposed to improve the organization of the section. Additional revisions are proposed to clarify language regarding what constitutes a valid Interpretation, including clarifying that requests for approval of specific compliance approaches are not proper Interpretation requests and should instead be pursued through the applicable NERC and Regional Entity guidance processes (Section 7.2.1).

Recognizing that Interpretations provide clarity to existing standards and do not create new compliance obligations, revisions are proposed to streamline the process for posting and balloting Interpretations. Specifically, revisions are proposed to: (i) reduce the time for comment from 45 days to 30 days; (ii) eliminate the requirement for Interpretation drafting teams to respond in writing to each submitted comment; and (iii) eliminate the need for a separate final ballot following a successful initial or additional ballot.

Section 8.0 - Process for Appealing an Action or Inaction

Revisions are proposed to Sections 8.1 and 8.2 to specify that an appellant may withdraw its Level 1 or Level 2 appeal by providing written notice to the NERC Director of Standards. These revisions, which are based on lessons learned from previous appeals, would allow an appellant to withdraw its appeal in the event the issue is resolved to the appellant's satisfaction prior to the formal conclusion of the appeal.

Section 11.0 - Process for Approving Supporting Documents

Revisions are proposed to clarify that the scope of Section 11 is to define a process for approving the posting of supporting documents to approved Reliability Standards (i.e., Reliability Standards approved by applicable governmental authorities). New subsections are created to improve organization. The revisions are summarized as follows:

Section 11.1 defines the types of documents that may be posted as a supporting document to an approved Reliability Standard (Reference, Lessons Learned, White Paper). This section specifically excludes documents that contain specific compliance approaches, which are properly addressed through the applicable NERC and Regional Entity guidance processes.

Section 11.2 defines the process to be used to review and vet proposals for supporting documents. This process is designed so that each supporting document posted alongside an approved Reliability Standard: (i) is a Reference, Lessons Learned, or White Paper as defined in Section 11.1; (ii) is consistent with the purpose and intent of the associated Reliability Standard; and (iii) has had adequate stakeholder review to assess its technical adequacy. For example, stakeholders may have reviewed the document for technical adequacy during the standard development process for the associated standard. Alternatively, Section 11 provides a process for posting for stakeholder review those proposed supporting documents that have not yet been sufficiently vetted.

Section 11.3 provides for SC approval to post the supporting document along with the approved Reliability Standard on the NERC website.

Updates to Other Sections

Updates are made to Section 2.1 - Definition of a Reliability Standard, to reflect the currently effective definition of this term in the NERC Rules of Procedure.

Updates are made to Section 3.7 - Governmental Authorities, to allow for the inclusion of federal and provincial governments of non-U.S. North American jurisdictions that may approve Reliability Standards in the future.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Processes Manual

VERSION ~~3~~4

Effective: ~~June 26, 2013~~TBD

to ensure the reliability of the bulk power system

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Section 1.0: Introduction

1.1: Authority
This manual is published by the authority of the NERC Board of Trustees. The Board of Trustees, as necessary to maintain NERC's certification as the Electric Reliability Organization ("ERO"), may file the manual with Applicable Governmental Authorities for approval as an ERO document. When approved, the manual is appended to and provides implementation detail in support of the ERO Rules of Procedure Section 300 — Reliability Standards Development.

Capitalized terms not otherwise defined herein, shall have the meaning set forth in the Definitions Used in the Rules of Procedure, Appendix 2 to the Rules of Procedure.

1.2: Scope
The policies and procedures in this manual shall govern the activities of the North American Electric Reliability Corporation ("NERC") related to the development, approval, revision, reaffirmation, and withdrawal of Reliability Standards, Interpretations, Violation Risk Factors ("VRFs"), Violation Severity Levels ("VSLs"), definitions, Variances, and reference documents developed to support standards for the Reliable Operation and planning of the North American Bulk Power Systems.

This manual also addresses the role of the Standards Committee, drafting team and ballot body in the development and approval of Compliance Elements in conjunction with standard development.

1.3: Background
NERC is a nonprofit corporation formed for the purpose of becoming the North American ERO. NERC works with all stakeholder segments of the electric industry, including electricity users, to develop Reliability Standards for the reliability planning and Reliable Operation of the North American Bulk Power Systems. In the United States, the Energy Policy Act of 2005 added Section 215 to the Federal Power Act for the purpose of establishing a framework to make Reliability Standards mandatory for all Bulk Power System owners, operators, and users. Similar authorities are provided by Applicable Governmental Authorities in Canada. NERC was certified as the ERO effective July 2006. *North American Electric Reliability Corp*., 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030 (2007).

1.4: Essential Attributes of NERC's Reliability Standards Processes
NERC's Reliability Standards development processes provide reasonable notice and opportunity for public comment, due process, openness, and balance of interests in developing a proposed Reliability Standard consistent with the attributes necessary for American National Standards Institute ("ANSI") accreditation. The same attributes, as well as transparency, consensus-building, and timeliness, are also required under the ERO Rules of Procedure Section 304.

- ***Open Participation***
  Participation in NERC's Reliability Standards development balloting and approval processes shall be open to all entities materially affected by NERC's Reliability Standards. There shall be no financial barriers to participation in NERC's Reliability Standards balloting and approval processes. Membership in the Registered Ballot Body shall not be conditional upon membership in any organization, nor unreasonably restricted on the basis of technical qualifications or other such requirements.

- ***Balance***
  NERC's Reliability Standards development processes shall not be dominated by any two interest categories, individuals, or organizations and no single interest category, individual, or organization is able to defeat a matter.

  NERC shall use a voting formula that allocates each industry Segment an equal weight in determining the final outcome of any Reliability Standard action. The Reliability Standards development processes shall have a balance of interests. Participants from diverse interest categories shall be encouraged to join the Registered Ballot Body and participate in the balloting process, with a goal of achieving balance between the interest categories. The Registered Ballot Body serves as the consensus body voting to approve each new or proposed Reliability Standard, definition, Variance, and Interpretation.

- ***Coordination and harmonization with other American National Standards activities***
  NERC is committed to resolving any potential conflicts between its Reliability Standards development efforts and existing American National Standards and candidate American National Standards.

- ***Notification of standards development***
  NERC shall publicly distribute a notice to each member of the Registered Ballot Body, and to each stakeholder who indicates a desire to receive such notices, for each action to create, revise, reaffirm, or withdraw a Reliability Standard, definition, or Variance; and for each proposed Interpretation. Notices shall be distributed electronically, with links to the relevant information, and notices shall be posted on NERC's Reliability Standards web page. All notices shall identify a readily available source for further information.

- ***Transparency***
  The process shall be transparent to the public.

- ***Consideration of views and objections***
  Drafting teams shall give prompt consideration to the written views and objections of all participants as set forth herein. Drafting teams shall make an effort to resolve each objection that is related to the topic under review.

- ***Consensus Building***
  The process shall build and document consensus for each Reliability Standard, both with regard to the need and justification for the Reliability Standard and the content of the Reliability Standard.

- ***Consensus vote***
  NERC shall use its voting process to determine if there is sufficient consensus to approve a proposed Reliability Standard, definition, Variance, or Interpretation. NERC shall form a ballot pool for each Reliability Standard action from interested members of its Registered Ballot Body. Approval of any Reliability Standard action requires:

  - A quorum, which is established by at least 75% of the members of the ballot pool submitting a response excluding unreturned ballots; and
  - A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast during all stages of balloting except the final ballot is the sum of affirmative and negative votes with comments, excluding abstentions, non-responses, and negative votes without comments. During the final ballot, the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

- ***Timeliness***
  Development of Reliability Standards shall be timely and responsive to new and changing priorities for reliability of the Bulk Power System.

- ***Metric Policy***
  The International System of units is the preferred units of measurement in NERC Reliability Standard. However, because NERC's Reliability Standards apply in Canada, the United States and portions of Mexico, where applicable, measures are provided in both the metric and English units.

1.5: Ethical Participation

All participants in the NERC Standard development process, including drafting teams, quality reviewers, Standards Committee members and members of the Registered Ballot Body, are obligated to act in an ethical manner in the exercise of all activities conducted pursuant to the terms and conditions of the Standard Processes Manual and the standard development process.

Section 2.0: Elements of a Reliability Standard

2.1: Definition of a Reliability Standard

A Reliability Standard includes a set of Requirements that define specific obligations of owners, operators, and users of the North American Bulk Power Systems. The Requirements shall be material to reliability and measurable. A Reliability Standard is defined as follows:

> "Reliability Standard" means a requirement, approved by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, or approved or recognized by an applicable governmental authority in other jurisdictions, to provide for Reliable Operation of the Bulk Power System., ~~including without limiting the foregoing,~~ The term includes requirements for the operation of existing Bulk Power System ~~Facilities~~facilities, including cyber-security protection, and ~~including~~ the design of planned additions or modifications to such ~~Facilities~~ facilities to the extent necessary for Reliable Operation of the Bulk Power System, but the term does not include any requirement to enlarge ~~Bulk Power System~~such ~~Facilities~~ facilities or to construct new transmission capacity or generation capacity. (In certain contexts, this term may also refer to a "Reliability Standard" that is in the process of being developed, or not yet approved or recognized by FERC or an applicable governmental authority in other jurisdictions). ~~A Reliability Standard shall not be effective in the United States until approved by the Federal Energy Regulatory Commission and shall not be effective in other jurisdictions until made or allowed to become effective by the Applicable Governmental Authority.~~ *See* Appendix 2 to the NERC Rules of Procedure, Definitions Used in the Rules of Procedure.

2.2: Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American Bulk Power Systems.[1] Each Reliability Standard shall enable or support one or more of the reliability principles, thereby ensuring that each Reliability Standard serves a purpose in support of reliability of the North American Bulk Power Systems. Each Reliability Standard shall also be consistent with all of the reliability principles, thereby ensuring that no Reliability Standard undermines reliability through an unintended consequence.

2.3: Market Principles

Recognizing that Bulk Power System reliability and electricity markets are inseparable and mutually interdependent, all Reliability Standards shall be consistent with the market interface principles.[2] Consideration of the market interface principles is intended to ensure that Reliability Standards are written such that they achieve their reliability objective without causing undue restrictions or adverse impacts on competitive electricity markets.

2.4: Types of Reliability Requirements

Generally, each Requirement of a Reliability Standard shall identify what Functional Entities shall do, and under what conditions, to achieve a specific reliability objective. Although Reliability Standards all follow this format, several types of Requirements may exist, each with a different approach to measurement.

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[1] The intent of the set of NERC Reliability Standards is to deliver an adequate level of reliability. The latest set of reliability principles and the latest set of characteristics associated with an adequate level of reliability are posted on the Reliability Standards Resources web page.

[2] The latest set of market interface principles is posted on the Reliability Standards Resources web page.

- **Performance-based Requirements** define a specific reliability objective or outcome achieved by one or more entities that has a direct, observable effect on the reliability of the Bulk Power System, *i.e.* an effect that can be measured using power system data or trends. In its simplest form, a performance-based requirement has four components: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome.*

- **Risk-based Requirements** define actions by one or more entities that reduce a stated risk to the reliability of the Bulk Power System and can be measured by evaluating a particular product or outcome resulting from the required actions. A risk-based reliability requirement should be framed as: *who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the Bulk Power System.*

- **Capability-based Requirements** define capabilities needed by one or more entities to perform reliability functions and can be measured by demonstrating that the capability exists as required. A capability-based reliability requirement should be framed as: *who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the Bulk Power System.*

The body of reliability Requirements collectively provides a defense-in-depth strategy supporting reliability of the Bulk Power System.

2.5: Elements of a Reliability Standard

A Reliability Standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Power System.

The components of a Reliability Standard may include the following:

Title: A brief, descriptive phrase identifying the topic of the Reliability Standard.

Number: A unique identification number assigned in accordance with a published classification system to facilitate tracking and reference to the Reliability Standards.[3]

Purpose: The reliability outcome achieved through compliance with the Requirements of the Reliability Standard.

Applicability: Identifies which entities are assigned reliability requirements. The specific Functional Entities and Facilities to which the Reliability Standard applies.

Effective Dates: Identification of the date or pre-conditions determining when each Requirement becomes effective in each jurisdiction.

Requirement: An explicit statement that identifies the Functional Entity responsible, the action or outcome that must be achieved, any conditions achieving the action or outcome, and the reliability-related benefit of the action or outcome. Each Requirement shall be a statement for which compliance is mandatory.

[3] Reliability Standards shall be numbered in accordance with the NERC Standards Numbering Convention as provide on the Reliability Standards Resources web page.

Compliance Elements: Elements to aid in the administration of ERO compliance monitoring and enforcement responsibilities.[4]

- ***Measure:*** Provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement.

- ***Violation Risk Factors and Violation Severity Levels:*** Violation risk factors (VRFs) and violation severity levels (VSLs) are used as factors when determining the size of a penalty or sanction associated with the violation of a requirement in an approved reliability standard.[5] Each requirement in each reliability standard has an associated VRF and a set of VSLs. VRFs and VSLs are developed by the drafting team, working with NERC Staff, at the same time as the associated reliability standard, but are not part of the reliability standard. The Board of Trustees is responsible for approving VRFs and VSLs.

  - ***Violation Risk Factors***
    VRFs identify the potential reliability significance of noncompliance with each requirement. Each requirement is assigned a VRF in accordance with the latest approved set of VRF criteria.[6]

  - ***Violation Severity Levels***
    VSLs define the degree to which compliance with a requirement was not achieved. Each requirement shall have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance and may have only one, two, or three VSLs. Each requirement is assigned one or more VSLs in accordance with the latest approved set of VSL criteria.[7]

Version History: The version history is provided for informational purposes and lists information regarding prior versions of Reliability Standards.

Variance: A Requirement (to be applied in the place of the continent-wide Requirement) that is applicable to a specific geographic area or to a specific set of Registered Entities.

Compliance Enforcement Authority: The entity that is responsible for assessing performance or outcomes to determine if an entity is compliant with the associated Reliability Standard. The Compliance Enforcement Authority will be NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

***Application guidelines*:** Guidelines to support the implementation of the associated Reliability Standard.

***Procedures*:** Procedures to support implementation of the associated Reliability Standard.

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[4] It is the responsibility of the ERO staff to develop compliance tools for each standard; these tools are not part of the standard but are referenced in this manual because the preferred approach to developing these tools is to use a transparent process that leverages the technical and practical expertise of the drafting team and ballot pool..
[5] The *Sanction Guidelines of the North American Electric Reliability Corporation* identifies the factors used to determine a penalty or sanction for violation of reliability standard and is posted on the NERC Web Site.
[6] The latest set of approved VRF Criteria is posted on the Reliability Standards Resources Web Page.
[7] The latest set of approved VSL Criteria is posted on the Reliability Standards Resources Web Page.

The only mandatory and enforceable components of a Reliability Standard are the: (1) applicability, (2) Requirements, and the (3) effective dates. The additional components are included in the Reliability Standard for informational purposes, to establish the relevant scope and technical paradigm, and to provide guidance to Functional Entities concerning how compliance will be assessed by the Compliance Enforcement Authority.

Section 3.0: Reliability Standards Program Organization

3.1: Board of Trustees

The NERC Board of Trustees shall consider for adoption Reliability Standards, definitions, Variances and Interpretations and associated implementation plans that have been processed according to the processes identified in this manual. Once the Board adopts a Reliability Standard, definition, Variance or Interpretation, the Board shall direct NERC Staff to file the document(s) for approval with Applicable Governmental Authorities.

3.2: Registered Ballot Body

The Registered Ballot Body comprises all entities or individuals that qualify for one of the Segments approved by the Board of Trustees[8], and are registered with NERC as potential ballot participants in the voting on Reliability Standards. Each member of the Registered Ballot Body is eligible to join the ballot pool for each Reliability Standard action.

3.3: Ballot Pool

Each Reliability Standard action has its own ballot pool formed of interested members of the Registered Ballot Body. The ballot pool comprises those members of the Registered Ballot Body that respond to a pre-ballot request to participate in that particular Reliability Standard action. The ballot pool votes on each Reliability Standards action. The ballot pool remains in place until all balloting related to that Reliability Standard action has been completed.

3.4: Standards Committee

The Standards Committee serves at the pleasure and direction of the NERC Board of Trustees, and the Board approves the Standards Committee's Charter.[9] Standards Committee members are elected by their respective Segment's stakeholders. The Standards Committee consists of two members of each of the Segments in the Registered Ballot Body.[10] A member of the NERC Reliability Standards Staff shall serve as the non-voting secretary to the Standards Committee.

The Standards Committee is responsible for managing the Reliability Standards processes for development of Reliability Standards, definitions, Variances and Interpretations in accordance with this manual. The responsibilities of the Standards Committee are defined in detail in the Standards Committee's Charter. The Standards Committee is responsible for ensuring that the Reliability Standards, definitions, Variances and Interpretations developed by drafting teams are developed in accordance with the processes in this manual and meet NERC's benchmarks for Reliability Standards as well as criteria for governmental approval.[11]

The Standards Committee has the right to remand work to a drafting team, to reject the work of a drafting team, or to accept the work of a drafting team. The Standards Committee may disband a drafting team if it determines (a) that the drafting team is not producing a standard in a timely manner; (b) the drafting team

[8] The industry Segment qualifications are described in the Development of the Registered Ballot Body and Segment Qualification Guidelines document posted on the Reliability Standards Resources web page and are included in Appendix 3D of the NERC Rules of Procedure.

[9] The Standards Committee Charter is posted on the Reliability Standards Resources web page.

[10] In addition to balanced Segment representation, the Standards Committee shall also have representation that is balanced among countries based on Net Energy for Load ("NEL"). As needed, the Board of Trustees may approve special procedures for the balancing of representation among countries represented within NERC.

[11] The Ten Benchmarks of an Excellent Reliability Standard and FERC's Criteria for Approving Reliability Standards are posted on the Reliability Standards Resources web page.

is not able to produce a standard that will achieve industry consensus; (c) the drafting team has not addressed the scope of the SAR; or (d) the drafting team has failed to fully address a regulatory directive or otherwise provided a responsive or equally efficient and effective alternative. The Standards Committee may direct a drafting team to revise its work to follow the processes in this manual or to meet the criteria for NERC's benchmarks for Reliability Standards, or to meet the criteria for governmental approval; however, the Standards Committee shall not direct a drafting team to change the technical content of a draft Reliability Standard.

The Standards Committee shall meet at regularly scheduled intervals (either in person, or by other means). All Standards Committee meetings are open to all interested parties.

3.5: NERC Reliability Standards Staff

The NERC Reliability Standards Staff, led by the Director of Standards, is responsible for administering NERC's Reliability Standards processes in accordance with this manual. The NERC Reliability Standards Staff provides support to the Standards Committee in managing the Reliability Standards processes and in supporting the work of all drafting teams. The NERC Reliability Standards Staff works to ensure the integrity of the Reliability Standards processes and consistency of quality and completeness of the Reliability Standards. The NERC Reliability Standards Staff facilitates all steps in the development of Reliability Standards, definitions, Variances, Interpretations and associated implementation plans.

The NERC Reliability Standards Staff is responsible for presenting Reliability Standards, definitions, Variances, and Interpretations to the NERC Board of Trustees for adoption. When presenting Reliability Standards-related documents to the NERC Board of Trustees for adoption or approval, the NERC Reliability Standards Staff shall report the results of the associated stakeholder ballot, including identification of unresolved stakeholder objections and an assessment of the document's practicality and enforceability.

3.6: Drafting Teams

The Standards Committee shall appoint industry experts to drafting teams to work with stakeholders in developing and refining Standard Authorization Requests ("SARs"), Reliability Standards, definitions, and Variances. The NERC Reliability Standards Staff shall appoint drafting teams that develop Interpretations. The NERC Reliability Standards Staff shall provide, or solicit from the industry, essential support for each of the drafting teams in the form of technical writers, legal, compliance, and rigorous and highly trained project management and facilitation support personnel.

Each drafting team may consist of a group of technical, legal, and compliance experts that work cooperatively with the support of the NERC Reliability Standards Staff.[12] The technical experts provide the subject matter expertise and guide the development of the technical aspects of the Reliability Standard, assisted by technical writers, legal and compliance experts. The technical experts maintain authority over the technical details of the Reliability Standard. Each drafting team appointed to develop a Reliability Standard is responsible for following the processes identified in this manual as well as procedures developed by the Standards Committee from the inception of the assigned project through the final acceptance of that project by Applicable Governmental Authorities.

Collectively, each drafting team:

- Drafts proposed language for the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

[12] The detailed responsibilities of drafting teams are outlined in the Drafting Team Guidelines, which is posted on the Reliability Standards Resources web page.

- Develops and refines technical documents that aid in the understanding of Reliability Standards.
- Works collaboratively with NERC Compliance Monitoring and Enforcement Staff to develop Reliability Standard Audit Worksheets ("RSAWs") at the same time Reliability Standards are developed.
- Provides assistance to NERC Staff in the development of Compliance Elements of proposed Reliability Standards.
- Solicits, considers, and responds to comments related to the specific Reliability Standards development project.
- Participates in industry forums to help build consensus on the draft Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.
- Assists in developing the documentation used to obtain governmental approval of the Reliability Standards, definitions, Variances, and/or Interpretations and associated implementation plans.

All drafting teams report to the Standards Committee.

3.7: Governmental Authorities

The Federal Energy Regulatory Commission ("FERC") in the United States of America, and where permissible by statute or regulation, the federal or provincial governments of other North American jurisdictions that have recognized NERC as the ERO ~~each of the eight Canadian Provinces (Manitoba, Nova Scotia, Saskatchewan, Alberta, Ontario, British Columbia, New Brunswick and Quebec) and the National Energy Board of Canada~~ have the authority to approve each new, revised or withdrawn Reliability Standard, definition, Variance, VRF, VSL and Interpretation following adoption or approval by the NERC Board of Trustees.

3.8: Committees, Subcommittees, Working Groups, and Task Forces

NERC's technical committees, subcommittees, working groups, and task forces provide technical research and analysis used to justify the development of new Reliability Standards and provide guidance, when requested by the Standards Committee, in overseeing field tests or collection and analysis of data. The technical committees, subcommittees, working groups, and task forces provide feedback to drafting teams during both informal and formal comment periods.

The Standards Committee may request that a NERC technical committee or other group prepare a Technical document to support development of a proposed Reliability Standard.

The technical committees, subcommittees, working groups, and task forces share their observations regarding the need for new or modified Reliability Standards or Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects for the three-year *Reliability Standards Development Plan*.

3.9: Compliance and Certification Committee

The Compliance and Certification Committee is responsible for monitoring NERC's compliance with its Reliability Standards processes and procedures and for monitoring NERC's compliance with the Rules of Procedure regarding the development of new or revised Reliability Standards, definitions, Variances, and Interpretations. The Compliance and Certification Committee may assist in verifying that each proposed Reliability Standard is enforceable as written before the Reliability Standard is posted for formal stakeholder comment and balloting.

3.10: Compliance Monitoring and Enforcement Program

As applicable, the NERC Compliance Monitoring and Enforcement Program Staff manages and enforces compliance with approved Reliability Standards. Compliance Monitoring and Enforcement Staff are responsible for the development of select compliance tools. The drafting team and the Compliance Monitoring and Enforcement Program Staff shall work together during the Reliability Standard development process to ensure an accurate and consistent understanding of the Requirements and their intent, and to ensure that applicable compliance tools accurately reflect that intent. The goal of this collaboration is to ensure that application of the Reliability Standards in the Compliance Monitoring and Enforcement Program by NERC and the Regional Entities is consistent.

The Compliance Monitoring and Enforcement Program is encouraged to share its observations regarding the need for new or modified Requirements with the NERC Reliability Standards Staff for use in identifying the need for new Reliability Standards projects.

3.11: North American Energy Standards Board ("NAESB")

While NERC has responsibility for developing Reliability Standards to support reliability, NAESB has responsibility for developing business practices and coordination between reliability and business practices as needed. NERC and NAESB developed and approved a procedure[13] to guide the development of Reliability Standards and business practices where the reliability and business practice components are intricately entwined within a proposed Reliability Standard.

[13] The NERC NAESB Template Procedure for Joint Standards Development and Coordination is posted on the Reliability Standards Resources web page.

Section 4.0: Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard

There are several steps to the development, modification, withdrawal or retirement of a Reliability Standard.[14]

The development of the *Reliability Standards Development Plan* is the appropriate forum for reaching agreement on whether there is a need for a Reliability Standard and the scope of a proposed Reliability Standard. A typical process for a project identified in the *Reliability Standards Development Plan* that involves a revision to an existing Reliability Standard is shown below. Note that most projects do not include a field test.

[14] The process described is also applicable to projects used to propose a new or modified definition or Variance or to propose retirement of a definition or Variance.

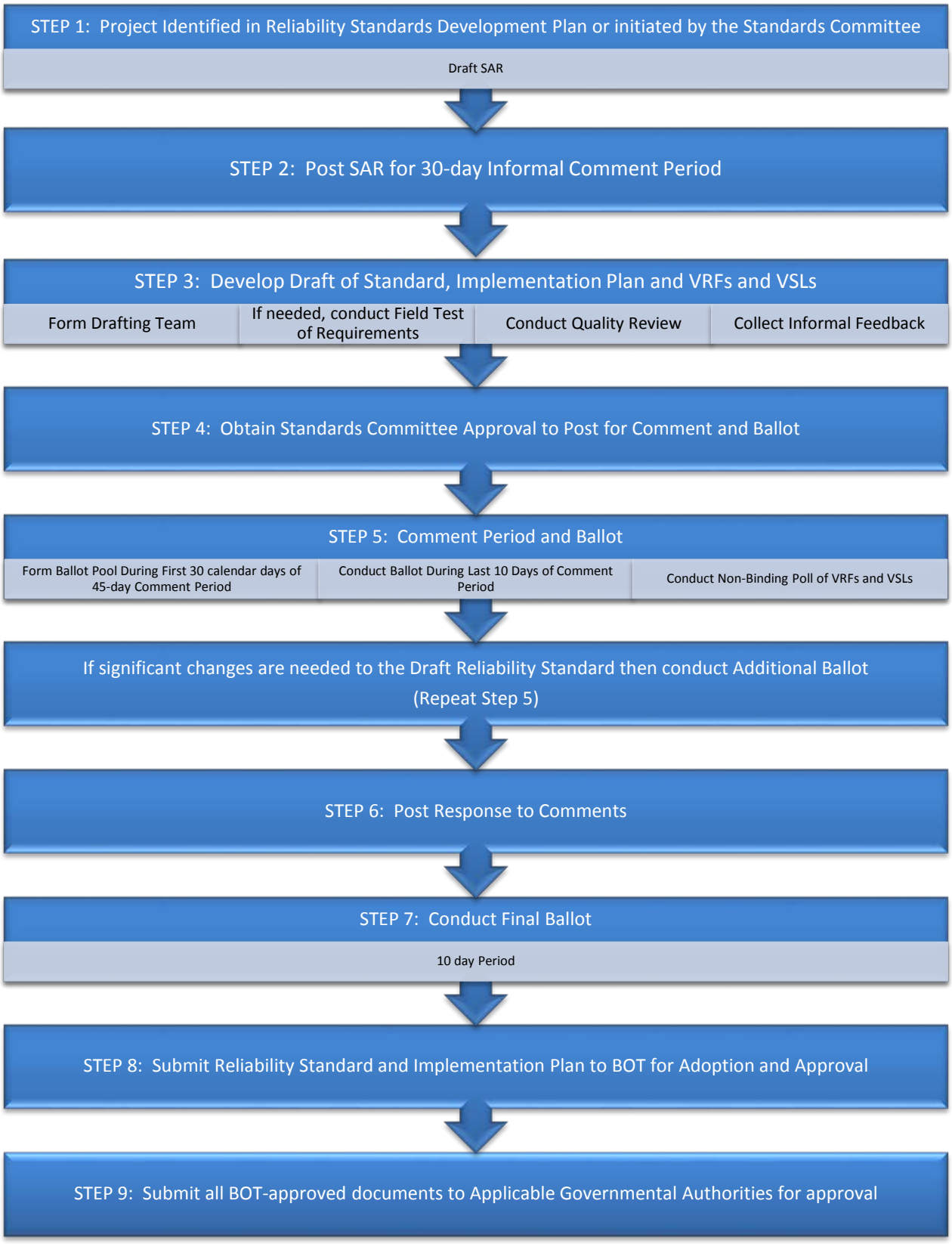


FIGURE 1: Process for Developing or Modifying a Reliability Standard

4.1: Posting and Collecting Information on SARs

Standard Authorization Request

A Standard Authorization Request ("SAR") is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified Reliability Standards or definitions or the benefit of retiring one or more approved Reliability Standards. Any entity or individual, including NERC committees or subgroups and NERC Staff, may propose the development of a new or modified Reliability Standard, or may propose the retirement of a Reliability Standard (in whole or in part), by submitting a completed SAR[15] to the NERC Reliability Standards Staff. The Standards Committee has the authority to approve the posting of all SARs for projects that propose (i) developing a new or modified Reliability Standard or definition or (ii) propose retirement of an existing Reliability Standard (or elements thereof).

The NERC Reliability Standards Staff sponsors an open solicitation period each year seeking ideas for new Reliability Standards projects (using *Reliability Standards Suggestions and Comments forms*). The open solicitation period is held in conjunction with the annual revision to the *Reliability Standards Development Plan*. While the Standards Committee prefers that ideas for new projects be submitted during this annual solicitation period through submittal of a *Reliability Standards Suggestions and Comments Form*,[16] a SAR proposing a specific project may be submitted to the NERC Reliability Standards Staff at any time.

Each SAR that proposes a "new" or substantially revised Reliability Standard or definition should be accompanied by a technical justification that includes, as a minimum, a discussion of the reliability-related benefits and costs of developing the new Reliability Standard or definition, and a technical foundation document (*e.g.*, research paper) to guide the development of the Reliability Standard or definition. The technical document should address the engineering, planning and operational basis for the proposed Reliability Standard or definition, as well as any alternative approaches considered during SAR development.

The NERC Reliability Standards Staff shall review each SAR and work with the submitter to verify that all required information has been provided. All properly completed SARs shall be submitted to the Standards Committee for action at the next regularly scheduled Standards Committee meeting.

When presented with a SAR, the Standards Committee shall determine if the SAR is sufficiently complete to guide Reliability Standard development and whether the SAR is consistent with this manual. The Standards Committee shall take one of the following actions:

- Accept the SAR.
- Remand the SAR back to the requestor or to NERC Reliability Standards Staff for additional work.
- Reject the SAR. The Standards Committee may reject a SAR for good cause. If the Standards Committee rejects a SAR, it shall provide a written explanation for rejection to the sponsor within ten days of the rejection decision.
- Delay action on the SAR pending one of the following: (i) development of a technical justification for the proposed project; or (ii) consultation with another NERC Committee to determine if there is another approach to addressing the issue raised in the SAR.

If the Standards Committee is presented with a SAR that proposes developing a new Reliability Standard or definition but does not have a technical justification upon which the Reliability Standard or definition can be developed, the Standards Committee shall direct the NERC Reliability Standards Staff to post the

[15] The SAR form can be downloaded from the Reliability Standards Resources web page.
[16] The *Reliability Standards Suggestions and Comments Form* can be downloaded from the Reliability Standards Resources web page.

SAR for a 30-day comment period solely to collect stakeholder feedback on the scope of technical foundation, if any, needed to support the proposed project. If a technical foundation is determined to be necessary, the Standards Committee shall solicit assistance from NERC's technical committees or other industry experts to provide that foundation before authorizing development of the associated Reliability Standard or definition.

During the SAR comment process, the drafting team may become aware of potential regional Variances related to the proposed Reliability Standard. To the extent possible, any regional Variances or exceptions should be made a part of the SAR so that if the SAR is authorized, such variations shall be made a part of the draft new or revised Reliability Standard.

If the Standards Committee accepts a SAR, the project shall be added to the list of approved projects. The Standards Committee shall assign a priority to the project, relative to all other projects under development, and those projects already identified in the *Reliability Standards Development Plan* that are already approved for development.

The Standards Committee shall work with the NERC Reliability Standards Staff to coordinate the posting of SARs for new projects, giving consideration to each project's priority.

4.2: SAR Posting

When the Standards Committee determines it is ready to initiate a new project, the Standards Committee shall direct NERC Staff to post the project's SAR in accordance with the following:

- For SARs that are limited to addressing regulatory directives, or revisions to Reliability Standards that have had some vetting in the industry, authorize posting the SAR for a 30-day informal comment period with no requirement to provide a formal response to the comments received.
- For SARs that address the development of new projects or Reliability Standards, authorize posting the SAR for a 30-day formal comment period.

If a SAR for a new Reliability Standard is posted for a formal comment period, the Standards Committee shall appoint a drafting team to work with the NERC Staff coordinator to give prompt consideration of the written views and objections of all participants. The Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise and work process skills to meet the objectives of the project. In some situations, an *ad hoc* team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to refine the SAR and develop the Reliability Standard, and additional members may not be needed. The drafting team shall address all comments submitted, which may be in the form of a summary response addressing each of the issues raised in comments received, during the public posting period. An effort to resolve all expressed objections shall be made, and each objector shall be advised of the disposition of the objection and the reasons therefore. If the drafting team concludes that there is not sufficient stakeholder support to continue to refine the SAR, the team may recommend that the Standards Committee direct curtailment of work on the SAR.

While there is no established limit on the number of times a SAR may be posted for comment, the Standards Committee retains the right to reverse its prior decision and reject a SAR if it believes continued revisions are not productive. The Standards Committee shall notify the sponsor in writing of the rejection within 10 calendar days.

If stakeholders indicate support for the project proposed with the SAR, the drafting team shall present its work to the Standards Committee with a request that the Standards Committee authorize development of the associated Reliability Standard.

The Standards Committee, once again considering the public comments received and their resolution, may then take one of the following actions:

- Authorize drafting the proposed Reliability Standard or revisions to a Reliability Standard.
- Reject the SAR with a written explanation to the sponsor and post that explanation.

4.3: Form Drafting Team

When the Standards Committee is ready to have a drafting team begin work on developing a new or revised Reliability Standard, the Standards Committee shall appoint a drafting team, if one was not already appointed to develop the SAR. If the Standards Committee appointed a drafting team to refine the SAR, the same drafting team shall work to develop the associated Reliability Standard.

If no drafting team is in place, then the Standards Committee may use a public nomination process to populate the Reliability Standard drafting team, or may use another method that results in a team that collectively has the necessary technical expertise, diversity of views and work process skills to accomplish the objectives of the project on a timely basis. In some situations, an ad hoc team may already be in place with the requisite expertise, competencies, and diversity of views that are necessary to develop the Reliability Standard, and additional members may not be needed.

The NERC Reliability Standards Staff shall provide one or more members as needed to support the team with facilitation, project management, compliance, legal, regulatory and technical writing expertise and shall provide administrative support to the team, guiding the team through the steps in completing its project. In developing the Reliability Standard, the individuals provided by the NERC Reliability Standards Staff serve as advisors to the drafting team and do not have voting rights but share accountability along with the drafting team members assigned by the Standards Committee for timely delivery of a final draft Reliability Standard that meets the quality attributes identified in NERC's Benchmarks for Excellent Standards. The drafting team members assigned by the Standards Committee shall have final authority over the technical details of the Reliability Standard, while the technical writer shall provide assistance to the drafting team in assuring that the final draft of the Reliability Standard meets the quality attributes identified in NERC's Benchmarks for Excellent Standards.

Once it is appointed by the Standards Committee, the Reliability Standard drafting team is responsible for making recommendations to the Standards Committee regarding the remaining steps in the Reliability Standards process. Consistent with the need to provide for timely standards development, the Standards Committee may decide a project is so large that it should be subdivided and either assigned to more than one drafting team or assigned to a single drafting team with clear direction on completing the project in specified phases. The normally expected timeframes for standards development within the context of this manual are applicable to individual standards and not to projects containing multiple standards. Alternatively, a single drafting team may address the entire project with a commensurate increase in the expected duration of the development work. If a SAR is subdivided and assigned to more than one drafting team, each drafting team will have a clearly defined portion of the work such that there are no overlaps and no gaps in the work to be accomplished.

The Standards Committee may supplement the membership of a Reliability Standard drafting team or provide for additional advisors, as appropriate, to ensure the necessary competencies and diversity of views are maintained throughout the Reliability Standard development effort.

4.4: Develop Preliminary Draft of Reliability Standard, Implementation Plan and VRFs and VSLs

4.4.1: Project Schedule

When a drafting team begins its work, either in refining a SAR or in developing or revising a proposed Reliability Standard, the drafting team shall develop a project schedule which shall be approved by the Standards Committee. The drafting team shall report progress to the Standards Committee, against the initial project schedule and any revised schedule as requested by the Standards Committee. Where project milestones cannot be completed on a timely basis, modifications to the project schedule must be presented to the Standards Committee for consideration along with proposed steps to minimize unplanned project delays.

4.4.2: Draft Reliability Standard

The team shall develop a Reliability Standard that is within the scope of the associated SAR that includes all required elements as described earlier in this manual with a goal of meeting the quality attributes identified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval. The team shall document its justification for the Requirements in its proposed Reliability Standard by explaining how each meets these criteria. The standard drafting team shall document its justification for selecting each reference by explaining how each Requirement fits the category chosen.

4.4.3: Implementation Plan

As a drafting team drafts its proposed revisions to a Reliability Standard, that team is also required to develop an implementation plan to identify any factors for consideration when approving the proposed effective date or dates for the associated Reliability Standard or Standards. As a minimum, the implementation plan shall include the following:

- The proposed effective date (the date entities shall be compliant) for the Requirements.
- Identification of any new or modified definitions that are proposed for approval with the associated Reliability Standard.
- Whether there are any prerequisite actions that need to be accomplished before entities are held responsible for compliance with one or more of the Requirements.
- Whether approval of the proposed Reliability Standard will necessitate any conforming changes to any already approved Reliability Standards – and identification of those Reliability Standards and Requirements.
- The Functional Entities that will be required to comply with one or more Requirements in the proposed Reliability Standard.

A single implementation plan may be used for more than one Reliability Standard. The implementation plan is posted with the associated Reliability Standard or Standards during the 45 (calendar) day formal comment period and is balloted with the associated Reliability Standard.

4.4.4: Violation Risk Factors and Violation Severity Levels

The drafting team shall work with NERC Staff in developing a set of VRFs and VSLs that meet the latest criteria established by NERC and Applicable Governmental Authorities. The drafting team shall document its justification for selecting each VRF and for setting each set of proposed VSLs by explaining how its proposed VRFs and VSLs meet these criteria. NERC Staff is responsible for ensuring that the VRFs and VSLs proposed for stakeholder review meet these criteria.

Before the drafting team has finalized its Reliability Standard, implementation plan, and VRFs and VSLs, the team should seek stakeholder feedback on its preliminary draft documents.

4.5: Informal Feedback[17]

Drafting teams may use a variety of methods to collect informal stakeholder feedback on preliminary drafts of its documents, including the use of informal comment periods,[18] webinars, industry meetings, workshops, or other mechanisms. Information gathered from informal comment forms shall be publicly posted. While drafting teams are not required to provide a written response to each individual comment received, drafting teams are encouraged, where possible, to post a summary response that identifies how it used comments submitted by stakeholders. Drafting teams are encouraged, where possible, to reach out directly to individual stakeholders in order to facilitate resolution of identified stakeholder concerns. The intent is to gather stakeholder feedback on a "working document" before the document reaches the point where it is considered the "final draft."

4.6: Conduct Quality Review

The NERC Reliability Standards Staff shall coordinate a quality review of the Reliability Standard, implementation plan, and VRFs and VSLs in parallel with the development of the Reliability Standard and implementation plan, to assess whether the documents are within the scope of the associated SAR, whether the Reliability Standard is clear and enforceable as written, and whether the Reliability Standard meets the criteria specified in NERC's Benchmarks for Excellent Standards and criteria for governmental approval of Reliability Standards. The drafting team shall consider the results of the quality review, decide upon appropriate changes, and recommend to the Standards Committee whether the documents are ready for formal posting and balloting.

The Standards Committee shall authorize posting the proposed Reliability Standard, and implementation plan for a formal comment period and ballot and the VRFs and VSLs for a non-binding poll as soon as the work flow will accommodate.

If the Standards Committee finds that any of the documents do not meet the specified criteria, the Standards Committee shall remand the documents to the drafting team for additional work.

If the Reliability Standard is outside the scope of the associated SAR, the drafting team shall be directed to either revise the Reliability Standard so that it is within the approved scope, or submit a request to expand the scope of the approved SAR. If the Reliability Standard is not clear and enforceable as written, or if the Reliability Standard does not meet the specified criteria, the Reliability Standard shall be returned to the drafting team by the Standards Committee with specific identification of any Requirement that is deemed to be unclear or unenforceable as written.

4.7: Conduct Formal Comment Period and Ballot

Proposed new or modified Reliability Standards require a formal comment period where the new or modified Reliability Standard, implementation plan and associated VRFs and VSLs or the proposal to retire a Reliability Standard, implementation plan and associated VRFs and VSLs are posted.

The formal comment period shall be at least 45-days long. Formation of the ballot pool and Ballot of the Reliability Standard take place during this formal 45-day comment period. The intent of the formal comment period(s) is to solicit very specific feedback on the final draft of the Reliability Standard, implementation plan and VRFs and VSLs.

[17] While this discussion focuses on collecting stakeholder feedback on proposed Reliability Standards and implementation plans, the same process is used to collect stakeholder feedback on proposed new or modified Interpretations, definitions and Variances.

[18] The term "informal comment period" refers to a comment period conducted outside of the ballot process and where there is no requirement for a drafting team to respond in writing to submitted comments.

Comments in written form may be submitted on a draft Reliability Standard by any interested stakeholder, including NERC Staff, FERC Staff, and other interested governmental authorities. If stakeholders disagree with some aspect of the proposed set of products, comments provided should explain the reasons for such disagreement and, where possible, suggest specific language that would make the product acceptable to the stakeholder.

4.8: Form Ballot Pool

The NERC Reliability Standards Staff shall establish a ballot pool during the first 30 calendar days of the 45-day formal comment period. The NERC Reliability Standards Staff shall post the proposed Reliability Standard, along with its implementation plan, VRFs and VSLs and shall send a notice to every entity in the Registered Ballot Body to provide notice that there is a new or revised Reliability Standard proposed for approval and to solicit participants for the associated ballot pool. All members of the Registered Ballot Body are eligible to join each ballot pool to vote on a new or revised Reliability Standard and its implementation plan and to participate in the non-binding poll of the associated VRFs and VSLs.

Any member of the Registered Ballot Body may join or withdraw from the ballot pool until the ballot window opens. No Registered Ballot Body member may join or withdraw from the ballot pool once the first ballot starts through the point in time where balloting for that Reliability Standard action has ended. The Director of Standards may authorize deviations from this rule for extraordinary circumstances such as the death, retirement, or disability of a ballot pool member that would prevent an entity that had a member in the ballot pool from eligibility to cast a vote during the ballot window. Any approved deviation shall be documented and noted to the Standards Committee.

4.9: Conduct Ballot and Non-binding Poll of VRFs and VSLs[19]

The NERC Reliability Standards Staff shall announce the opening of the Ballot window and the non-binding poll of VRFs and VSLs. The Ballot window and non-binding poll of VRFs and VSLs shall take place during the last 10 calendar days of the 45-day formal comment period and for the Final Ballot shall be no less than 10 calendar days. If the last day of the ballot window falls on a Saturday or Sunday, the period does not end until the next business day.[20]

The ballot and non-binding poll shall be conducted electronically. The voting window shall be for a period of 10 calendar days but shall be extended, if needed, until a quorum is achieved. During a ballot window, NERC shall not sponsor or facilitate public discussion of the Reliability Standard action under ballot.

There is no requirement to conduct a new non-binding poll of the revised VRFs and VSLs if no changes were made to the associated standard, however if the requirements are modified and conforming changes are made to the associated VRFs and VSLs, another non-binding poll of the revised VRFs and VSLs shall be conducted.

[19] While RSAWs are not part of the Reliability Standard, they are developed through collaboration of the SDT and NERC Compliance Staff. A non-binding poll, similar to what is done for VRFs and VSLs may be conducted for the RSAW developed through this process to gauge industry support for the companion RSAW to be provided for informational purposes to the NERC Board of Trustees.

[20] Closing dates may be extended as deemed appropriate by NERC Staff.

4.10: Criteria for Ballot Pool Approval

Ballot pool approval of a Reliability Standard requires:

A quorum, which is established by at least 75% of the members of the ballot pool submitting a response; and

A two-thirds majority of the weighted Segment votes cast shall be affirmative. The number of votes cast is the sum of affirmative votes and negative votes with comments. This calculation of votes for the purpose of determining consensus excludes (i) abstentions, (ii) non-responses, and (iii) negative votes without comments.

The following process[21] is used to determine if there are sufficient affirmative votes.

- For each Segment with ten or more voters, the following process shall be used: The number of affirmative votes cast shall be divided by the sum of affirmative and negative votes with comments cast to determine the fractional affirmative vote for that Segment. Abstentions, non-responses, and negative votes without comments shall not be counted for the purposes of determining the fractional affirmative vote for a Segment.
- For each Segment with less than ten voters, the vote weight of that Segment shall be proportionally reduced. Each voter within that Segment voting affirmative or negative with comments shall receive a weight of 10% of the Segment vote.
- The sum of the fractional affirmative votes from all Segments divided by the number of Segments voting[22] shall be used to determine if a two-thirds majority has been achieved. (A Segment shall be considered as "voting" if any member of the Segment in the ballot pool casts either an affirmative vote or a negative vote with comments.)
- A Reliability Standard shall be approved if the sum of fractional affirmative votes from all Segments divided by the number of voting Segments is at least two thirds.

4.11: Voting Positions

Each member of the ballot pool may **only** vote one of the following positions on the Ballot and Additional Ballot(s):

- Affirmative;
- Affirmative, with comment;
- Negative with comments;
- Abstain.

Given that there is no formal comment period concurrent with the Final Ballot, each member of the ballot pool may **only** vote one of the following positions on the Final Ballot:

- Affirmative;
- Negative;[23]
- Abstain.

[21] Examples of weighted segment voting calculation are posted on the Reliability Standards Resources web page.

[22] When less than ten entities vote in a Segment, the total weight for that Segment shall be determined as one tenth per entity voting, up to ten.

[23] The Final Ballot is used to confirm consensus achieved during the Formal Comment and Ballot stage. Ballot Pool members voting negative on the Final Ballot will be deemed to have expressed the reason for their negative ballot in their own comments or the comments of others during prior Formal Comment periods.

4.12: Consideration of Comments
If a stakeholder or balloter proposes a significant revision to a Reliability Standard during the formal comment period or concurrent Ballot that will improve the quality, clarity, or enforceability of that Reliability Standard, then the drafting team may choose to make such revisions and post the revised Reliability Standard for another 45 calendar day public comment period and ballot. Prior to posting the revised Reliability Standard for an additional comment period, the drafting team must communicate this decision to stakeholders. This communication is intended to inform stakeholders that the drafting team has identified that significant revisions to the Reliability Standard are necessary and should note that the drafting team is not required to respond in writing to comments from the previous ballot. The drafting team will respond to comments received in the last Additional Ballot prior to conducting a Final Ballot.

There is no formal comment period concurrent with the Final Ballot and no obligation for the drafting team to respond to any comments submitted during the Final Ballot.

4.13: Additional Ballots
A drafting team must respond in writing to every stakeholder written comment submitted in response to a ballot prior to conducting a Final Ballot. These responses may be provided in summary form, but all comments and objections must be responded to by the drafting team. All comments received and all responses shall be publicly posted.

However, a drafting team is not required to respond in writing to comments to the previous ballot when it determines that significant changes are needed and an Additional Ballot will be conducted.

4.14: **Conduct Final Ballot**
When the drafting team has reached a point where it has made a good faith effort at resolving applicable objections and is not making any substantive changes from the previous ballot, the team shall conduct a "Final Ballot." A non-substantive revision is a revision that does not change the scope, applicability, or intent of any Requirement and includes but is not limited to things such as correcting the numbering of a Requirement, correcting the spelling of a word, adding an obviously missing word, or rephrasing a Requirement for improved clarity. Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination.

In the Final Ballot, members of the ballot pool shall again be presented the proposed Reliability Standard along with the reasons for negative votes from the previous ballot, the responses of the drafting team to those concerns, and any resolution of the differences.

All members of the ballot pool shall be permitted to reconsider and change their vote from the prior ballot. Members of the ballot pool who did not respond to the prior ballot shall be permitted to vote in the Final Ballot. In the Final Ballot, votes shall be counted by exception only — members on the Final Ballot may indicate a revision to their original vote; otherwise their vote shall remain the same as in their prior ballot.

4.15: Final Ballot Results
There are no limits to the number of public comment periods and ballots that can be conducted to result in a Reliability Standard or interpretation that is clear and enforceable, and achieves a quorum and sufficient affirmative votes for approval. The Standards Committee has the authority to conclude this process for a particular Reliability Standards action if it becomes obvious that the drafting team cannot develop a Reliability Standard that is within the scope of the associated SAR, is sufficiently clear to be enforceable, and achieves the requisite weighted Segment approval percentage.

The NERC Reliability Standards Staff shall post the final outcome of the ballot process. If the Reliability Standard is rejected, the Standards Committee may decide whether to end all further work on the proposed standard, return the project to informal development, or continue holding ballots to attempt to reach

consensus on the proposed standard. If the Reliability Standard is approved, the Reliability Standard shall be posted and presented to the Board of Trustees by NERC management for adoption and subsequently filed with Applicable Governmental Authorities for approval.

4.16: Board of Trustees Adoption of Reliability Standards, Implementation Plan and VRFs and VSLs

If a Reliability Standard and its associated implementation plan are approved by its ballot pool, the Board of Trustees shall consider adoption of that Reliability Standard and its associated implementation plan and shall direct the standard to be filed with Applicable Governmental Authorities for approval. In making its decision, the Board shall consider the results of the balloting and unresolved dissenting opinions. The Board shall adopt or reject a Reliability Standard and its implementation plan, but shall not modify a proposed Reliability Standard. If the Board chooses not to adopt a Reliability Standard, it shall provide its reasons for not doing so.

The board shall consider approval of the VRFs and VSLs associated with a reliability standard. In making its determination, the board shall consider the following:

- The Standards Committee shall present the results of the non-binding poll conducted and a summary of industry comments received on the final posting of the proposed VRFs and VSLs.
- NERC Staff shall present a set of recommended VRFs and VSLs that considers the views of the standard drafting team, stakeholder comments received on the draft VRFs and VSLs during the posting for comment process, the non-binding poll results, appropriate governmental agency rules and directives, and VRF and VSL assignments for other Reliability Standards to ensure consistency and relevance across the entire spectrum of Reliability Standards.

4.17: Compliance

For a Reliability Standard to be enforceable, it shall be approved by its ballot pool, adopted by the NERC Board of Trustees, and approved by Applicable Governmental Authorities, unless otherwise approved by the NERC Board of Trustees pursuant to the NERC Rules of Procedure (*e.g*, Section 321) and approved by Applicable Governmental Authorities. Once a Reliability Standard is approved or otherwise made mandatory by Applicable Governmental Authorities, all persons and organizations subject to jurisdiction of the ERO will be required to comply with the Reliability Standard in accordance with applicable statutes, regulations, and agreements.

4.18: Withdrawal of a Reliability Standard, Interpretation, or Definition

The term "withdrawal" as used herein, refers to the discontinuation of a Reliability Standard, Interpretation, Variance or definition that has been approved by the Board of Trustees and (1) has not been filed with Applicable Governmental Authorities, or (2) has been filed with, but not yet approved by, Applicable Governmental Authorities. The Standards Committee may withdraw a Reliability Standard, Interpretation or definition for good cause upon approval by the Board of Trustees. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities, as needed, to allow for withdrawal. The Board of Trustees also has an independent right of withdrawal that is unaffected by the terms and conditions of this Section.

4.19: Retirement of a Reliability Standard, Interpretation, or Definition

The term "retirement" refers to the discontinuation of a Reliability Standard, Interpretation or definition that has been approved by Applicable Governmental Authorities. A Reliability Standard, Variance or Definition may be retired when it is superseded by a revised version, and in such cases the retirement of the

earlier version is to be noted in the implementation plan presented to the ballot pool for approval and the retirement shall be considered approved by the ballot pool upon ballot pool approval of the revised version.

Upon identification of a need to retire a Reliability Standard, Variance, Interpretation or definition, where the item will not be superseded by a new or revised version, a SAR containing the proposal to retire a Reliability Standard, Variance, Interpretation or definition will be posted for a comment period and ballot in the same manner as a Reliability Standard. The proposal shall include the rationale for the retirement and a statement regarding the impact of retirement on the reliability of the Bulk Power System. Upon approval by the Board of Trustees, NERC Staff will petition the Applicable Governmental Authorities to allow for retirement.

Section 5.0: Process for Developing a Defined Term

NERC maintains a glossary of approved terms, entitled the *Glossary of Terms Used in NERC Reliability Standards*[24] ("Glossary of Terms"). The Glossary of Terms includes terms that have been through the formal approval process and are used in one or more NERC Reliability Standards. Definitions shall not contain statements of performance Requirements. The Glossary of Terms is intended to provide consistency throughout the Reliability Standards.

There are several methods that can be used to add, modify or retire a defined term used in a continent-wide Reliability Standard.

- Anyone can use a Standard Authorization Request ("SAR") to submit a request to add, modify, or retire a defined term.
- Anyone can submit a Standards Comments and Suggestions Form recommending the addition, modification, or retirement of a defined term. (The suggestion would be added to a project and incorporated into a SAR.)
- A drafting team may propose to add, modify, or retire a defined term in conjunction with the work it is already performing.

5.1: Proposals to Develop a New or Revised Definition

The following considerations should be made when considering proposals for new or revised definitions:

- Some NERC Regional Entities have defined terms that have been approved for use in Regional Reliability Standards, and where the drafting team agrees with a term already defined by a Regional Entity, the same definition should be adopted if needed to support a NERC Reliability Standard.
- If a term is used in a Reliability Standard according to its common meaning (as found in a collegiate dictionary), the term shall not be proposed for addition to the Glossary of Terms.
- If a term has already been defined, any proposal to modify or delete that term shall consider all uses of the definition in approved Reliability Standards, with a goal of determining whether the proposed modification is acceptable, and whether the proposed modification would change the scope or intent of any approved Reliability Standards.
- When practical, where NAESB has a definition for a term, the drafting team shall use the same definition to support a NERC Reliability Standard.

Any definition that is balloted separately from a proposed new or modified Reliability Standard or from a proposal for retirement of a Reliability Standard shall be accompanied by an implementation plan.

If a SAR is submitted to the NERC Reliability Standards Staff with a proposal for a new or revised definition, the Standards Committee shall consider the urgency of developing the new or revised definition and may direct NERC Staff to post the SAR immediately, or may defer posting the SAR until a later time based on its priority relative to other projects already underway or already approved for future development. If the SAR identifies a term that is used in a Reliability Standard already under revision by a drafting team, the Standards Committee may direct the drafting team to add the term to the scope of the existing project. Each time the Standards Committee accepts a SAR for a project that was not identified in the *Reliability Standards Development Plan*, the project shall be added to the list of approved projects.

[24] The latest approved version of the Glossary of Terms is posted on the NERC website on the Standards web page.

5.2: Stakeholder Comments and Approvals

Any proposal for a new or revised definition shall be processed in the same manner as a Reliability Standard and quality review shall be conducted in parallel with this process. Once authorized by the Standards Committee, the proposed definition and its implementation plan shall be posted for at least one formal stakeholder comment period and shall be balloted in the same manner as a Reliability Standard. If a new or revised definition is proposed by a drafting team, that definition may be balloted separately from the associated Reliability Standard.

Each definition that is approved by its ballot pool shall be submitted to the NERC Board of Trustees for adoption and then filed with Applicable Governmental Authorities for approval in the same manner as a Reliability Standard.

Section 6.0: Processes for Conducting Field Tests and Collecting and Analyzing Data

While most drafting teams can develop their Reliability Standards without the need to conduct any field tests and without the need to collect and analyze data, some Reliability Standard development efforts may require benefit from field tests to analyze data and validate concepts in the development of Reliability Standards. Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.

There are two types of field tests – tests of concepts and tests of requirements. A field test is initiated by either a SAR or Reliability Standard drafting team. The drafting team may be supplemented with other individuals based on the required technical expertise needed to support the field test. The drafting team is responsible for developing the field test plan, including the implementation schedule, and for identifying compliance related issues such as the potential need for compliance waivers.

6.1: Field Tests and Data Analysis for Validation of Concepts (collectively "field test")

- Field tests or collection and analysis of data to validate concepts that support the development of Requirements Reliability Standards should be conducted, to the extent possible, before the SAR for a project is finalized. If an entity wants to test a technical concept in support of a proposal for a new or revised Reliability Standard, the entity should either work with one of NERC's technical committees in collecting and analyzing the data or in conducting the field test, or the entity should submit a SAR with a request to collect and analyze data or conduct a field test to validate the concept prior to developing a new or revised Reliability Standard. The request to collect and analyze data or conduct a field test should include, at a minimum, either the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the analysis of the results. If the SAR sponsor has not collected and analyzed the data or conducted the field test, the Standards Committee may solicit support from NERC's technical committees or others in the industry. The results of the data collection and analysis or field test shall then be used to determine whether to add the SAR to the list of projects in the Reliability Standard Development Plan.
- To conduct a field test of a technical concept in a proposed new or revised Reliability Standard, the drafting team must work with NERC Staff to identify one of NERC's technical committees to oversee the field test as well as other technical committees with relevant technical expertise.
- The field test is conducted by the drafting team, in coordination with NERC Staff and under the oversight of the assigned technical committee, in accordance with an approved field test plan.

If a drafting team finds that it needs to collect and analyze data or conduct a field test of a concept that was not identified when the SAR was accepted, then the Standards Committee may direct the team to withdraw the SAR until the data has been collected and analyzed or until the field test has been conducted and the industry has had an opportunity to review the results for the impact on the scope of the proposed project.

6.1.1. Field Test Approval

The request to conduct a field test shall include, at a minimum:

- the field test plan,
- the implementation schedule, and
- an expectation for periodic updates of the analysis of the results to the lead NERC technical committee.

Prior to the drafting team conducting a field test, the drafting team must first receive approval from the lead NERC technical committee. Second, the drafting team must receive approval from the Standards Committee.

The lead NERC technical committee's approval shall be based on the technical adequacy of the field test plan. Following approval, the lead NERC technical committee shall provide a recommendation to the Standards Committee for the disposition of the field test plan request. The lead NERC technical committee shall coordinate all entity participation in the field test, such as accepting, adding, and withdrawing individual entities from the field test, as well as coordinating and communicating status of the results of the field test.

The Standards Committee's decision to approve the field test plan request shall be based solely on whether the Standards Committee, by majority vote, agrees or disagrees with the lead NERC technical committee's recommendation. If the Standards Committee disagrees with the lead NERC technical committee's recommendation, the Standards Committee shall inform the lead NERC technical committee with an explanation of the basis for the decision.

6.1.2: Field Test Suspension for Reliability Concerns

During the field test, if the lead NERC technical committee overseeing the field test determines that the field test is creating a reliability risk to the Bulk Power System:

- the lead NERC technical committee shall stop or modify the activity;
- the lead NERC technical committee shall inform the Standards Committee that the activity was stopped or modified;
- the Standards Committee, with the assistance of NERC Staff, shall document the cessation or modification of the field test; and
- the Standards Committee, with the assistance of NERC Staff, shall notify NERC Compliance Monitoring and Enforcement Program Staff to coordinate any compliance related issues such as continuance or cessation of waivers (see Section 6.2).

Prior to the field test being restarted after it has been stopped, the drafting team must resubmit the field test request and receive approval as outlined in Section 6.1.1.

6.1.3: Continuing, Modifying, or Terminating a Field Test

If the drafting team concludes that a field test does not provide sufficient information to formulate a conclusion within the time allotted in the plan, the drafting team shall provide a recommendation to either continue (including extending the duration of the field test beyond the period of standard development), modify, or terminate the field test to the lead NERC technical committee and the chair of the Standards Committee. The lead NERC technical committee shall either approve or reject a request to continue, modify, or terminate the field test, and thereafter, provide notice to the chair of the Standards Committee of its selection.

If the duration of the field test is extended beyond the period of standard development, the preliminary report and results shall be publicly posted on the NERC web site prior to the final ballot of the Reliability Standard.

~~**6.2: Field Tests and Data Analysis for Validation of Requirements**~~

~~If a drafting team wants to conduct a field test or collect and analyze data to validate its proposed Requirements in a Reliability Standard, the team shall first obtain approval from the Standards~~

Committee.[25] Drafting teams are not required to collect and analyze data or to conduct a field test to validate a Reliability Standard.

The request should include at a minimum the data collection and analysis or field test plan, the implementation schedule, and an expectation for periodic updates of the results. When authorizing a drafting team to collect and analyze data or to conduct a field test of one or more Requirements, the Standards Committee may request inputs on technical matters related from NERC's technical committees or industry experts, and may request the assistance of the Compliance Monitoring and Enforcement Program. All data collection and analysis and all field tests shall be concluded and the results incorporated into the Reliability Standard Requirements as necessary before proceeding to the formal comment period and subsequent balloting.

6.32: Communication and Coordination for All Types of Field Tests and Data Analyses

If the conduct of a field test (concepts or Requirements) or data collection and analysis could After approval of the field test, the drafting team may request waivers of compliance for field test participants that would be rendered Registered Entities incapable of complying with the current Requirement(s) of an approveda currently enforceable Reliability Standard that is undergoing revision, the drafting team shall request a temporary waiver from compliance to those Requirements for entities participating in the field test due to their participation. Upon request, the Standards Committee shall seek approval for the waiver from the The NERC Compliance Monitoring and Enforcement Program Staff prior to the approval of the field test or data collection and analysisshall determine whether to approve the requested waivers and shall be responsible for approving any modifications or terminations that may become necessary following the start of the field test. The NERC Reliability Standards Staff shall inform the affected Registered Entities. Prior to initiation of the field test, the chair of the Standards Committee, in conjunction with the lead NERC technical committee chair, shall inform the Board of Trustees of the pending field test, the expected duration, and any requested waivers of compliance for Registered Entities.

During the field test, the drafting team shall provide periodic updates (no less than quarterly) on the progress of the field test to the Standards Committee and the NERC technical committees. Prior to the ballot of any standard involving a field test, the drafting team shall provide to the Standards Committee either a preliminary report of the results of the field test to date, if the field test will continue beyond standard development, or a final report if the field test has been completed. The chair of the Standards Committee shall keep the Board of Trustees informed.

Once a plan for a field test or a plan for data collection and analysis is approved, the NERC Reliability Standards Staff shall, under the direction of the Standards Committee, coordinate the implementation of the field test or data collection and analysis and shall provide official notice to the participants in the field test or data collection of any applicable temporary waiver to compliance with specific noted Requirements. The drafting team conducting the field test shall provide periodic updates on the progress of the field tests or data collection and analysis to the Standards Committee. The Standards Committee has the right to curtail a field test or data collection and analysis that is not implemented in accordance with the approved plan.

The field test plan or data collection and analysis plan, its approval, its participants, and all reports and results shall be publicly posted for stakeholder review on the NERC Reliability Standards web pagesite. This posting shall include the participant list, unless it is determined that posting this list would present confidentiality or other concerns.

[25] The Process for Approving Data Collection and Analysis and Field Tests Associated with a Reliability Standard is posted on the Reliability Standards Resources web page.

If a drafting team conducts or participates in a field test or in data collection and analysis (of concepts or Requirements), it shall provide a final report that identifies the results and how those results will be used.

Section 7.0: Process for Developing an Interpretation

A valid Interpretation request is one that requests additional clarity about one or more Requirements in approved NERC Reliability Standards, but does not request approval as to how to comply with one or more Requirements. A valid Interpretation response provides additional clarity about one or more Requirements, but does not expand on any Requirement and does not explain how to comply with any Requirement. Any entity that is directly and materially affected by the reliability of the North American Bulk Power Systems may request an Interpretation of any Requirement in any continent-wide Reliability Standard that has been adopted by the NERC Board of Trustees. Interpretations will only be provided for Board of Trustees-approved Reliability Standards *i.e.* (i) the current effective version of a Reliability Standard; or (ii) a version of a Reliability Standard with a future effective date.

7.1: Valid Interpretation

An Interpretation may only clarify ~~or interpret~~ the language of the Requirement(s) of an approved Reliability Standard, including, if applicable, any attachment referenced in the Requirement ~~being clarified~~. The Interpretation may not alter the scope or the language of a Requirement or referenced attachment. No other elements of an approved Reliability Standard are subject to an Interpretation.

7.2: Process for Requesting an Interpretation

The entity requesting the Interpretation shall submit a *Request for Interpretation* form[26] to the NERC Reliability Standards Staff explaining the clarification required, the specific circumstances surrounding the request, and the impact of not having the Interpretation provided. ~~The~~ NERC Reliability Standards and Legal Staff~~s~~ shall review the request for ~~interpretation~~ Interpretation to determine whether it meets the requirements for a valid ~~interpretation~~Interpretation. Based on this review, ~~the~~ NERC ~~Standards and Legal~~ Staff~~s~~ shall make a recommendation to the Standards Committee whether to accept the request for Interpretation and move forward in responding to the Interpretation request.

7.2.1: Rejection of an Interpretation Request

~~For example, an~~A request for Interpretation ~~request~~ may be rejected ~~where it~~in the following circumstances:

- ~~(1)~~ Where the r~~R~~equest~~s~~ seeks approval of a particular compliance approach.[27] ~~;~~
- ~~(2) Identifies a gap or perceived weakness in the approved Reliability Standard;~~
- ~~(3)~~ Where ~~an~~ the issue can be addressed by incorporating the issue into an ~~active~~ existing or future standard ~~drafting team~~development project.~~;~~
- ~~(4)~~ Where ~~it~~ the request~~s~~ seeks clarification of any element of a Reliability Standard other than a Requirement.~~;~~
- ~~(5)~~ Where ~~a question~~the issue has already been addressed in the record.~~;~~
- ~~(6)~~ Where the ~~Interpretation~~ request identifies an issue and proposes the development of a new or modified Reliability Standard~~,~~ (such issues should be addressed via submission of a SAR).~~;~~
- ~~(7)~~ Where ~~an Interpretation~~the request seeks to expand the scope of a Reliability Standard.~~; or~~
- ~~(8)~~ Where the meaning of a Reliability Standard is plain on its face.

[26] The *Request for Interpretation* form is posted on the NERC Standards web page.

[27] Requests that contain specific compliance approaches, or examples of compliance, are not candidates for Interpretations and should be pursued through the applicable NERC Compliance Monitoring and Enforcement Program processes.

If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for the ~~rejecting the Interpretation~~rejection to the entity requesting the Interpretation within 10 business days of the decision to reject.

7.2.2: Acceptance of an Interpretation Request

If the Standards Committee accepts the Interpretation request, the Standards Committee shall authorize NERC Reliability Standards Staff ~~shall (i) form a ballot pool and (ii)~~to assemble an Interpretation drafting team with the relevant expertise to address the request~~interpretation for approval by the Standards Committee~~.

7.3: Development of an Interpretation

As soon as practical, the Interpretation drafting team shall develop a ~~"final~~ draft~~"~~ Interpretation ~~providing the requested clarity~~addressing the request, consistent with Section 7.1. Interpretations shall be developed in accordance with the following process:

- NERC Reliability Standards staff shall review the draft Interpretation to determine whether it has met the requirements for a valid Interpretation and to provide a recommendation to the Standards Committee whether to authorize posting or remand to the Interpretation drafting team for further work.
- The Standards Committee, after review of the Staff recommendation, may authorize posting of the draft Interpretation for comment and ballot.
- Interpretations ~~will~~ shall be balloted in the same manner as Reliability Standards (*see* Section 4.0), with the following exceptions:
  - Interpretations shall be posted for a 30-day informal comment period. The Interpretation drafting team is not required to respond in writing to comments submitted during this comment period.
  - The NERC Reliability Standards Staff shall establish a ballot pool during the first 20 days of the 30-day informal comment period.
  - The ballot window shall take place during the last 10 calendar days of the 30-day informal comment period.
  - Final Ballots shall not be conducted for Interpretations. An Interpretation shall be deemed approved by the ballot pool following the first ballot in which the necessary quorum and sufficient affirmative votes are obtained.

If ~~stakeholder comments~~the ballot results indicate that there is not a consensus for the Interpretation, and the Interpretation drafting team cannot revise the Interpretation without violating the basic ~~expectations~~ criteria ~~outlined above~~for what constitutes a valid Interpretation (see Section 7.1), the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with the proposed modification to the Reliability Standard. The entity that requested the Interpretation shall be notified in writing and the disposition of the Interpretation shall be posted.

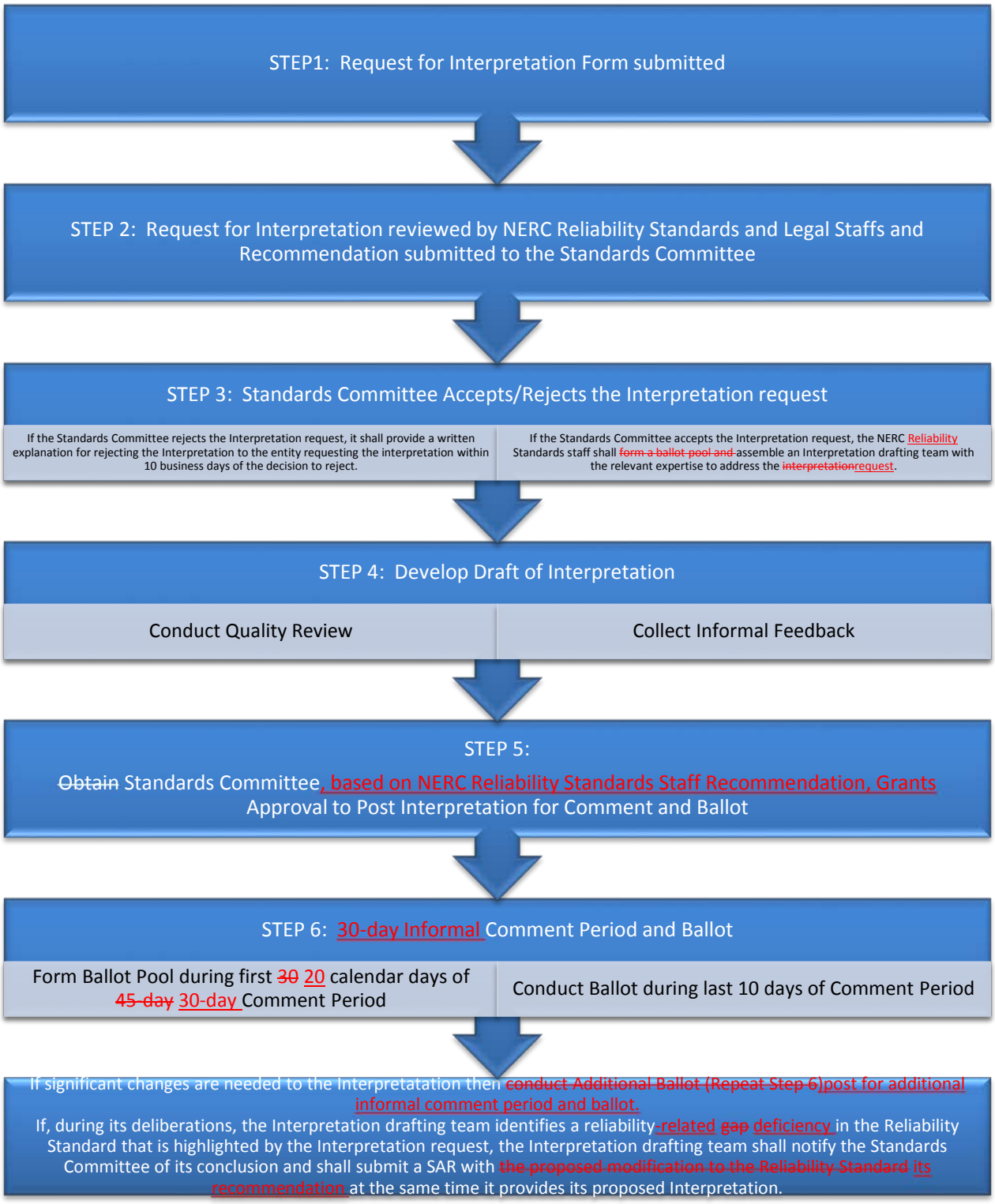
If, during its deliberations, the Interpretation drafting team identifies a reliability-related ~~gap~~ deficiency in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR with ~~the proposed modification to the Reliability Standard~~its recommendation at the same time it provides its proposed Interpretation.

If approved by the ballot pool, ~~The~~ NERC ~~Reliability Standards and Legal~~ Staff~~s~~ shall review the final Interpretation to determine whether it has met the requirements for a valid Interpretation and ~~. Based on this review, the NERC Standards and Legal Staffs~~ shall make a recommendation to the NERC Board of Trustees regarding adoption.

~~If approved by its ballot pool, the Interpretation shall be forwarded to the NERC Board of Trustees for adoption.[28]~~ If an Interpretation drafting team ~~proposes~~ recommends a modification to a Reliability Standard as part of its work in developing an Interpretation, the Board of Trustees shall be notified of this ~~proposal~~ recommendation at the time the Interpretation is submitted for adoption. Following ~~adoption by the~~ Board of Trustees adoption, ~~NERC Staff shall file~~ the Interpretation shall be filed ~~for approval by~~with the Applicable Governmental Authorities, and the Interpretation shall become effective when approved by those Applicable Governmental Authorities.[29] The Interpretation shall stand until ~~such time as~~ the Interpretation can be incorporated into a future revision of the Reliability Standard or the Interpretation is retired due to a future modification of the applicable Requirement.

~~[28] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.~~

[29] NERC will maintain a record of all interpretations associated with each standard on the Reliability Standards page of the NERC website.


STEP1: Request for Interpretation Form submitted
STEP 2: Request for Interpretation reviewed by NERC Reliability Standards and Legal Staffs and Recommendation submitted to the Standards Committee
STEP 3: Standards Committee Accepts/Rejects the Interpretation request
If the Standards Committee rejects the Interpretation request, it shall provide a written explanation for rejecting the Interpretation to the entity requesting the interpretation within 10 business days of the decision to reject.
If the Standards Committee accepts the Interpretation request, the NERC Reliability Standards staff shall form a ballot pool and assemble an Interpretation drafting team with the relevant expertise to address the interpretationrequest.
STEP 4: Develop Draft of Interpretation
Conduct Quality Review
Collect Informal Feedback
STEP 5:
Obtain Standards Committee, based on NERC Reliability Standards Staff Recommendation, Grants Approval to Post Interpretation for Comment and Ballot
STEP 6: 30-day Informal Comment Period and Ballot
Form Ballot Pool during first 30 20 calendar days of 45-day 30-day Comment Period
Conduct Ballot during last 10 days of Comment Period
If significant changes are needed to the Interpretatation then conduct Additional Ballot (Repeat Step 6)post for additional informal comment period and ballot.
If, during its deliberations, the Interpretation drafting team identifies a reliability-related gap deficiency in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and shall submit a SAR with the proposed modification to the Reliability Standard its recommendation at the same time it provides its proposed Interpretation.

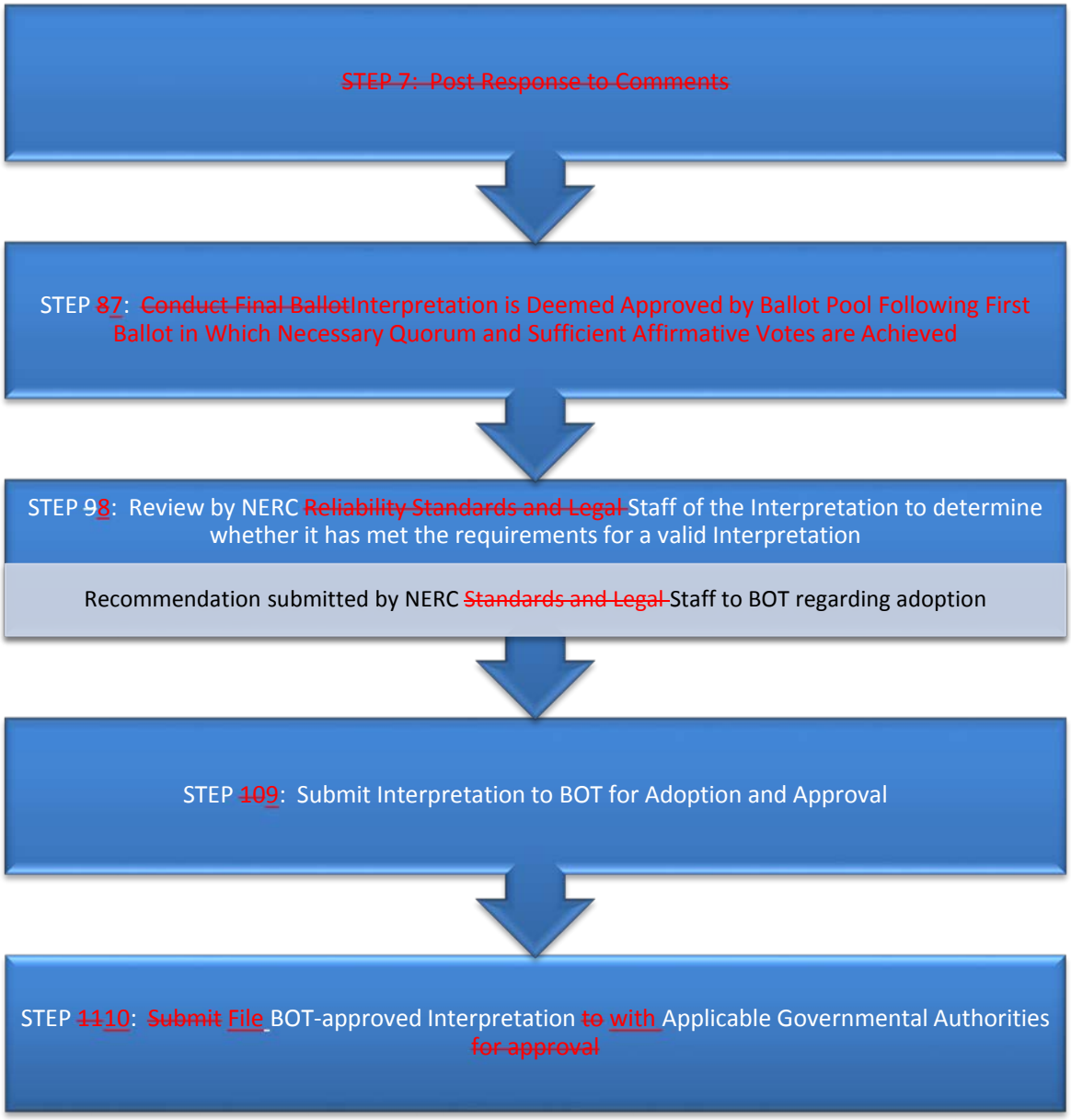


FIGURE 2: Process for Developing an Interpretation

Section 8.0: Process for Appealing an Action or Inaction

Any entity that has directly and materially affected interests and that has been or will be adversely affected by any procedural action or inaction related to the development, approval, revision, reaffirmation, retirement or withdrawal of a Reliability Standard, definition, Variance, associated implementation plan, or Interpretation shall have the right to appeal. This appeals process applies only to the NERC Reliability Standards processes as defined in this manual, not to the technical content of the Reliability Standards action.

The burden of proof to show adverse effect shall be on the appellant. Appeals shall be made in writing within 30 days of the date of the action purported to cause the adverse effect, except appeals for inaction, which may be made at any time. The final decisions of any appeal shall be documented in writing and made public.

The appeals process provides two levels, with the goal of expeditiously resolving the issue to the satisfaction of the participants.

8.1: Level 1 Appeal

Level 1 is the required first step in the appeals process. The appellant shall submit (to the Director of Standards) a complaint in writing that describes the procedural action or inaction associated with the Reliability Standards process. The appellant shall describe in the complaint the actual or potential adverse impact to the appellant. Assisted by NERC Staff and industry resources as needed, the Director of Standards shall prepare a written response addressed to the appellant as soon as practical but not more than 45 days after receipt of the complaint. If the appellant accepts the response as a satisfactory resolution of the issue, both the complaint and response shall be made a part of the public record associated with the Reliability Standard.

At any time prior to receiving the written response to the Level 1 Appeal, an appellant may withdraw the Level 1 Appeal with written notice to the Director of Standards.

8.2: Level 2 Appeal

If after the Level 1 Appeal the appellant remains unsatisfied with the resolution, as indicated by the appellant in writing to the Director of Standards, the Director of Standards shall convene a Level 2 Appeals Panel. This panel shall consist of five members appointed by the Board of Trustees. In all cases, Level 2 Appeals Panel members shall have no direct affiliation with the participants in the appeal.

The NERC Reliability Standards Staff shall post the complaint and other relevant materials and provide at least 30 days notice of the meeting of the Level 2 Appeals Panel. In addition to the appellant, any entity that is directly and materially affected by the procedural action or inaction referenced in the complaint shall be heard by the panel. The panel shall not consider any expansion of the scope of the appeal that was not presented in the Level 1 Appeal. The panel may, in its decision, find for the appellant and remand the issue to the Standards Committee with a statement of the issues and facts in regard to which fair and equitable action was not taken. The panel may find against the appellant with a specific statement of the facts that demonstrate fair and equitable treatment of the appellant and the appellant's objections. The panel may not, however, revise, approve, disapprove, or adopt a Reliability Standard, definition, Variance or Interpretation or implementation plan as these responsibilities remain with the ballot pool and Board of Trustees respectively. The actions of the Level 2 Appeals Panel shall be publicly posted.

At any time prior to the meeting of the Level 2 Appeals Panel, an appellant may withdraw the Level 2 Appeal and accept the results of the Level 1 Appeal by providing written notice to the Director of Standards.

In addition to the foregoing, a procedural objection that has not been resolved may be submitted to the Board of Trustees for consideration at the time the Board decides whether to adopt a particular Reliability Standard, definition, Variance or Interpretation. The objection shall be in writing, signed by an officer of the objecting entity, and contain a concise statement of the relief requested and a clear demonstration of the facts that justify that relief. The objection shall be filed no later than 30 days after the announcement of the vote by the ballot pool on the Reliability Standard in question.

Section 9.0: Process for Developing a Variance

A Variance is an approved, alternative method of achieving the reliability intent of one or more Requirements in a Reliability Standard. No Regional Entity or Bulk Power System owner, operator, or user shall claim a Variance from a NERC Reliability Standard without approval of such a Variance through the relevant Reliability Standard approval procedure for the Variance. Each Variance from a NERC Reliability Standard that is approved by NERC and Applicable Governmental Authorities shall be made an enforceable part of the associated NERC Reliability Standard.

NERC's drafting teams shall aim to develop Reliability Standards with Requirements that apply on a continent-wide basis, minimizing the need for Variances while still achieving the Reliability Standard's reliability objectives. If one or more Requirements cannot be met or complied with as written because of a physical difference in the Bulk Power System or because of an operational difference (such as a conflict with a federally or provincially approved tariff), but the Requirement's reliability objective can be achieved in a different fashion, an entity or a group of entities may pursue a Variance from one or more Requirements in a continent-wide Reliability Standard. It is the responsibility of the entity that needs a Variance to identify that need and initiate the processing of that Variance through the submittal of a SAR[30] that includes a clear definition of the basis for the Variance.

There are two types of Variances – those that apply on an Interconnection-wide basis, and those that apply to one or more entities on less than an Interconnection-wide basis.

9.1: Interconnection-wide Variances

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to Registered Entities within a Regional Entity organized on an Interconnection-wide basis shall be considered an Interconnection-wide Variance and shall be developed through that Regional Entity's NERC-approved Regional Reliability Standards development procedure.

While an Interconnection-wide Variance may be developed through the associated Regional Reliability Standards development process, Regional Entities are encouraged to work collaboratively with existing continent-wide drafting teams to reduce potential conflicts between the two efforts.

An Interconnection-wide Variance from a NERC Reliability Standard that is determined by NERC to be just, reasonable, and not unduly discriminatory or preferential, and in the public interest, and consistent with other applicable standards of governmental authorities shall be made part of the associated NERC Reliability Standard. NERC shall rebuttably presume that an Interconnection-wide Variance from a NERC Reliability Standard that is developed, in accordance with a Regional Reliability Standards development procedure approved by NERC, by a Regional Entity organized on an Interconnection-wide basis, is just, reasonable, and not unduly discriminatory or preferential, and in the public interest.

9.2: Variances that Apply on Less than an Interconnection-wide Basis

Any Variance from a NERC Reliability Standard Requirement that is proposed to apply to one or more entities but less than an entire Interconnection (*e.g.*, a Variance that would apply to a regional transmission organization or particular market or to a subset of Bulk Power System owners, operators, or users), shall be considered a Variance. A Variance may be requested while a Reliability Standard is under development or a Variance may be requested at any time after a Reliability Standard is approved. Each request for a

[30] A sample of a SAR that identifies the need for a Variance and a sample Variance are posted as resources on the Reliability Standards Resources web page.

Variance shall be initiated through a SAR, and processed and approved in the same manner as a continent-wide Reliability Standard, using the Reliability Standards development process defined in this manual.

Section 10.0: Processes for Developing a Reliability Standard Related to a Confidential Issue

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC has an obligation as the ERO to ensure that there are Reliability Standards in place to preserve the reliability of the interconnected Bulk Power Systems throughout North America. When faced with a national security emergency situation, NERC may use one of the following special processes to develop a Reliability Standard that addresses an issue that is confidential. Reliability Standards developed using one of the following processes shall be called, "special Reliability Standards" and shall not be filed with ANSI for approval as American National Standards.

The NERC Board of Trustees may direct the development of a new or revised Reliability Standard to address a national security situation that involves confidential issues. These situations may involve imminent or long-term threats. In general, these Board directives will be driven by information from the President of the United States of America or the Prime Minister of Canada or a national security agency or national intelligence agency of either or both governments indicating (to the ERO) that there is a national security threat to the reliability of the Bulk Power System.[31]

There are two special processes for developing Reliability Standards responsive to confidential issues – one process where the confidential issue is "imminent," and one process where the confidential issue is "not imminent."

10.1: Process for Developing Reliability Standards Responsive to Imminent, Confidential Issues
If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.2: Drafting Team Selection
The Reliability Standard drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.3: Work of Drafting Team
The Reliability Standard drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The Reliability Standard drafting team shall review its work, to the extent practical, as it is being developed with officials from the appropriate governmental agencies in the U.S. and Canada, under strict security and confidentiality rules.

10.4: Formal Stakeholder Comment & Ballot Window

[31] The NERC Board may direct the immediate development and issuance of a Level 3 (Essential Action) alert and then may also direct the immediate development of a new or revised Reliability Standard.

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[32] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

The drafting team, working with the NERC Reliability Standards Staff, shall consider and respond to all comments, make any necessary conforming changes to the Reliability Standard and its implementation plan, and shall distribute the comments, responses and any revision to the same population as received the initial set of documents for formal comment and ballot.

10.5: Board of Trustee Actions
Each Reliability Standard and implementation plan developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.6: Governmental Approvals
All approved documents shall be filed for approval with Applicable Governmental Authorities.

[32] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

10.7: Developing a Reliability Standard Responsive to an Imminent, Confidential Issue

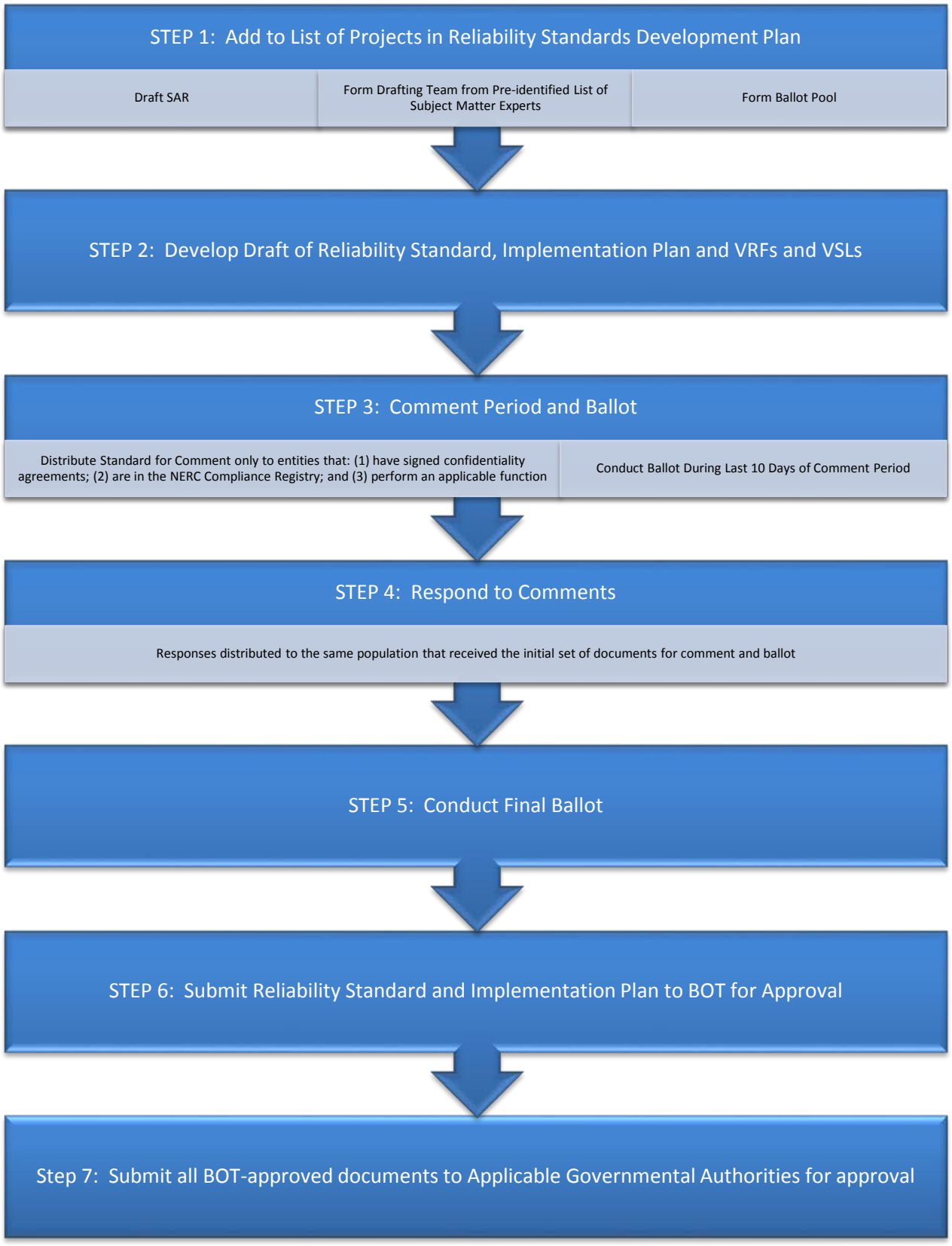


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

10.8: Process for Developing Reliability Standards Responsive to Non-imminent, Confidential Issues

If the NERC Board of Trustees directs the immediate development of a new or revised Reliability Standard to address a confidential national security emergency situation, the NERC Reliability Standards Staff shall develop a SAR, form a ballot pool (to vote on the Reliability Standard and its implementation plan) and assemble a slate of pre-defined subject matter experts as a proposed drafting team for approval by the Standards Committee's officers. All members of the Registered Ballot Body shall have the opportunity to join the ballot pool.

10.9: Drafting Team Selection

The drafting team selection process shall be limited to just those candidates who have already been identified as having the appropriate security clearance, the requisite technical expertise, and either have signed or are willing to sign a strict confidentiality agreement.

10.10: Work of Drafting Team

The drafting team shall perform all its work under strict security and confidential rules. The Reliability Standard drafting team shall develop the new or revised Reliability Standard and its implementation plan.

The drafting team shall review its work, to the extent practical, as it is being developed with officials from the Applicable Governmental Authorities, under strict security and confidentiality rules.

10.11: Formal Stakeholder Comment & Ballot Window

The draft Reliability Standard and its implementation plan shall be distributed for a formal comment period, under strict confidentiality rules, only to those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.[33] At the same time, the Reliability Standard shall be distributed to the members of the ballot pool for review and ballot. The NERC Reliability Standards Staff shall not post or provide the ballot pool with any confidential background information.

10.12: Revisions to Reliability Standard, Implementation Plan and VRFs and VSLs

The drafting team, working with the NERC Reliability Standards Staff, shall work to refine the Reliability Standard, implementation plan and VRFs and VSLs in the same manner as for a new Reliability Standard following the "normal" Reliability Standards development process described earlier in this manual with the exception that distribution of the comments, responses, and new drafts shall be limited to those entities that are in the ballot pool and those entities that are listed in the NERC Compliance Registry to perform one of the functions identified in the applicability section of the Reliability Standard and have identified individuals from their organizations that have signed confidentiality agreements with NERC.

10.13: Board of Trustee Action

Each Reliability Standard, implementation plan, and the associated VRFs and VSLs developed through this process shall be submitted to the NERC Board of Trustees for adoption.

10.14: Governmental Approvals

All BOT-approved documents shall be filed for approval with Applicable Governmental Authorities.

[33] In this phase of the process, only the proposed Reliability Standard shall be distributed to those entities expected to comply, not the rationale and justification for the Reliability Standard. Only the special drafting team members, who have the appropriate security credentials, shall have access to this rationale and justification.

Developing a Reliability Standard Responsive to a Non-imminent, Confidential Issue

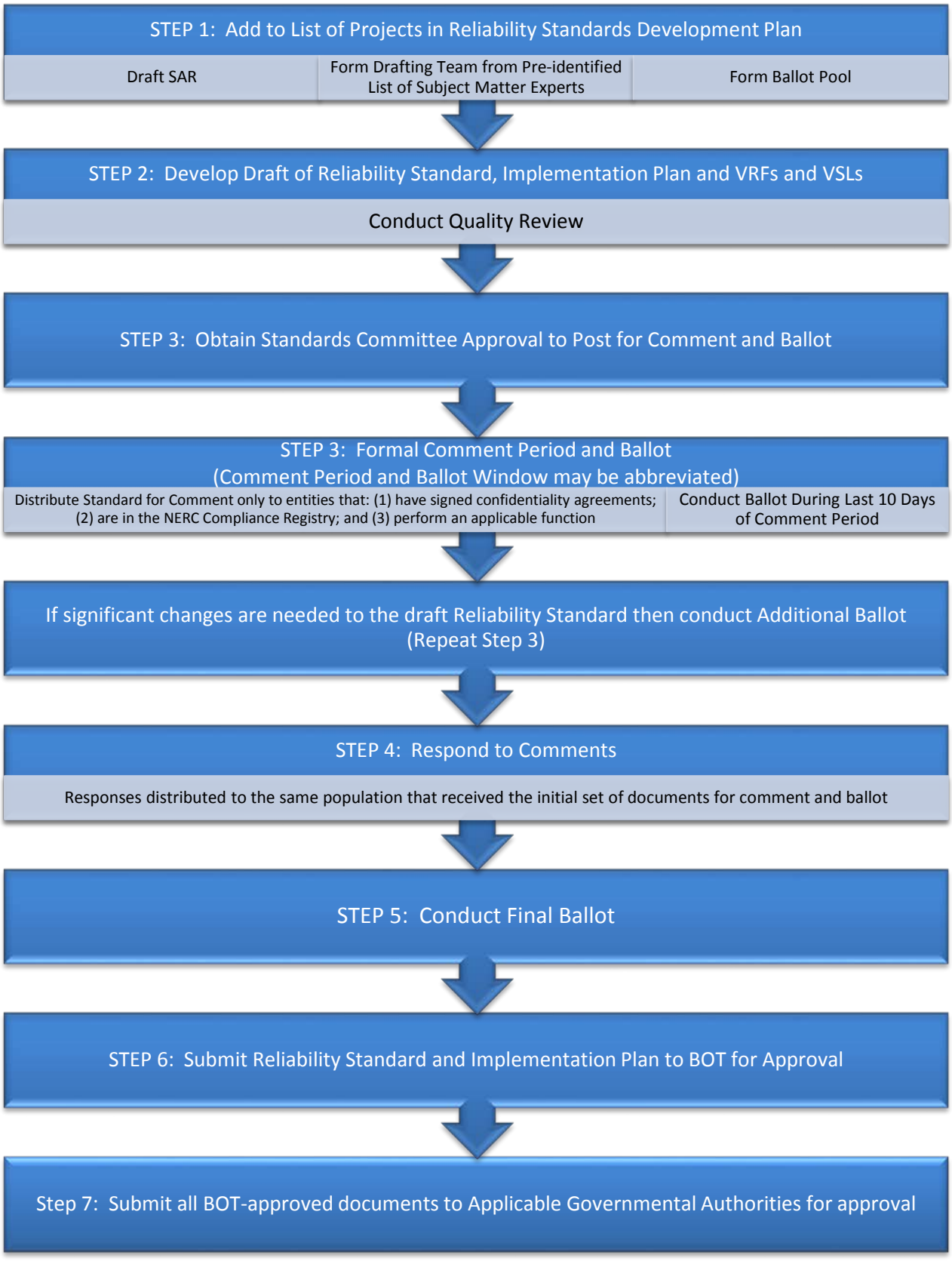


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

Section 11.0: Process for Approving Supporting Documents

The NERC Standards Committee oversees the development and approval of documents identified as supporting documents to Reliability Standards approved by the Applicable Governmental Authority. ~~The following types of documents are samples of the types of supporting documents that may be developed to enhance stakeholder understanding and implementation of a Reliability Standard. These~~ Supporting documents may explain or facilitate ~~implementation~~ understanding of Reliability Standards but do not themselves contain mandatory Requirements subject to compliance review. Any Requirements that are mandatory shall be incorporated into the Reliability Standard in the Reliability Standard development process.

~~While most supporting documents are developed by the standard drafting team working to develop the associated Reliability Standard, any entity may develop a supporting document associated with a Reliability Standard.~~ This Section provides the mechanism by which any stakeholder may propose a supporting document to an approved Reliability Standard.

~~The Standards Committee shall authorize the posting of all supporting references[34] that are linked to an approved Reliability Standard. Prior to granting approval to post a supporting reference with a link to the associated Reliability Standard, the Standards Committee shall verify~~ The process outlined in this section is designed so that each~~that the~~ supporting document ~~has had~~ receives stakeholder review to verify the accuracy of the technical content prior to being posted as a supporting document to an approved Reliability Standard. ~~While the Standards Committee has the authority to approve the posting of each such reference, stakeholders, not the Standards Committee, verify the accuracy of the document's contents.~~

11.1: Types of Supporting Documents

The types of supporting documents that may be approved under this Section are listed below.

Type of Document	Description
Reference	Descriptive, technical information or analysis or explanatory information to support the understanding ~~and interpretation~~ of an approved Reliability Standard. ~~A standard reference may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.~~
~~Guideline~~	~~Recommended process that identifies a method of meeting a Requirement under specific conditions.~~
~~Supplement~~	~~Data forms, pro forma documents, and associated instructions that support the implementation of a Reliability Standard.~~
~~Training Material~~	~~Documents that support the implementation of a Reliability Standard.~~

[34] ~~The Standards Committee's Procedure for Approving the Posting of Reference Documents is posted on the Reliability Standards Resources web page.~~

~~Procedure~~	~~Step-wise instructions defining a particular process or operation. Procedures may support the implementation of a Reliability Standard or satisfy another purpose consistent with the reliability and market interface principles.~~
Lessons Learned	Documents designed to convey lessons learned related to an approved Reliability Standard. A Lessons Learned document is not intended to establish new Requirements under NERC's Reliability Standards or to modify Requirements in any existing Reliability Standards.
White Paper	An informal paper stating a position or concept. A white paper may have been used to propose preliminary concepts for a Reliability Standard or ~~one of the documents above~~a Reference document.

Supporting documents do not include documents that contain specific compliance approaches or examples of compliance. Such documents would be developed in accordance with the applicable NERC Compliance Monitoring and Enforcement Program process.

11.2: Process for Proposing and Evaluating Supporting Documents

Proposals for supporting documents to approved Reliability Standards shall be submitted to the NERC Reliability Standards Staff.

NERC Staff shall conduct a review of the proposed supporting document. In performing this review, NERC Staff may consult any technical resources it deems appropriate. The purpose of this review is to determine whether the proposed supporting document meets the following three criteria:

1. the document is a type of supporting document subject to this Section, as described in Section 11.1;
2. the document is consistent with the purpose and intent of the associated Reliability Standard; and
3. the document has received adequate stakeholder review to assess its technical adequacy, such as through a NERC technical committee review process, public comment period(s) held during the development of the associated Reliability Standard, or other stakeholder review process.

Where NERC Staff determines that the proposed supporting document has met the three criteria specified above, NERC Staff shall submit the proposed supporting document to the Standards Committee as specified in Section 11.3 below.

Where NERC Staff determines that the proposed supporting document does not meet the first or second criteria specified above, NERC Staff shall notify the submitter that the document will not be posted as a supporting document under this Section. This notification shall be made in writing with an explanation of the basis for the decision. NERC Staff shall also notify the Standards Committee of this determination at the next regularly scheduled Standards Committee meeting.

Where NERC Staff determines that the proposed supporting document meets the first and second criteria, but has not yet received adequate stakeholder review under the third criteria, NERC Staff shall make a recommendation to the Standards Committee to authorize the posting of the proposed supporting document for stakeholder review to verify the accuracy of the technical content. This comment period shall be for 30 days, unless directed otherwise by the Standards Committee. Upon conclusion of the comment period, NERC Staff shall compile the comments and provide to the submitter for consideration. If the submitter

modifies the proposed supporting document based on stakeholder comments, NERC Staff may post the document for additional comment periods to provide for sufficient vetting and technical review.

11.3: Approving a Supporting Document

Following its determination that the proposed supporting document has met the three criteria specified in Section 11.2, NERC Staff shall present the supporting document to the NERC Standards Committee with a recommendation regarding whether the Standards Committee should approve posting the supporting document with the approved Reliability Standard on the pertinent NERC website page(s).

Section 12.0: Process for Correcting Errata

From time to time, an error may be discovered in a Reliability Standard. Such errors may be corrected (i) following a Final Ballot prior to Board of Trustees adoption, (ii) following Board of Trustees adoption prior to filing with Applicable Governmental Authorities; and (iii) following filing with Applicable Governmental Authorities. If the Standards Committee agrees that the correction of the error does not change the scope or intent of the associated Reliability Standard, and agrees that the correction has no material impact on the end users of the Reliability Standard, then the correction shall be filed for approval with Applicable Governmental Authorities as appropriate. The NERC Board of Trustees has resolved to concurrently approve any errata approved by the Standards Committee.

Section 13.0: Process for Conducting Periodic Reviews of Reliability Standards

All Reliability Standards shall be reviewed at least once every ten years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later. If a Reliability Standard is approved by ANSI as an American National Standard, it shall be reviewed at least once every five years from the effective date of the Reliability Standard or the date of the latest Board of Trustees adoption to a revision of the Reliability Standard, whichever is later.

The *Reliability Standards Development Plan* shall include projects that address this five or ten-year review of Reliability Standards.

- If a Reliability Standard is nearing its five or ten-year review and has issues that need resolution, then the *Reliability Standards Development Plan* shall include a project for the complete review and associated revision of that Reliability Standard that includes addressing all outstanding governmental directives, all approved Interpretations, and all unresolved issues identified by stakeholders.
- If a Reliability Standard is nearing its five or ten-year review and there are no outstanding governmental directives, Interpretations, or unresolved stakeholder issues associated with that Reliability Standard, then the Reliability *Standards Development Plan* shall include a project solely for the "five-year review" of that Reliability Standard.

For a project that is focused solely on the five-year review, the Standards Committee shall appoint a review team of subject matter experts to review the Reliability Standard and recommend whether the American National Standard Institute-approved Reliability Standard should be reaffirmed, revised, or withdrawn. Each review team shall post its recommendations for a 45 calendar day formal stakeholder comment period and shall provide those stakeholder comments to the Standards Committee for consideration.

- If a review team recommends reaffirming a Reliability Standard, the Standards Committee shall submit the reaffirmation to the Board of Trustees for adoption and then to Applicable Governmental Authorities for approval. Reaffirmation does not require approval by stakeholder ballot.
- If a review team recommends modifying, or retiring a Reliability Standard, the team shall develop a SAR with such a proposal and the SAR shall be submitted to the Standards Committee for prioritization as a new project. Each existing Reliability Standard recommended for modification, or retirement shall remain in effect in accordance with the associated implementation plan until the action to modify or withdraw the Reliability Standard is approved by its ballot pool, adopted by the Board of Trustees, and approved by Applicable Governmental Authorities.

In the case of reaffirmation of a Reliability Standard, the Reliability Standard shall remain in effect until the next five or ten-year review or until the Reliability Standard is otherwise modified or withdrawn by a separate action.

Section 14.0: Public Access to Reliability Standards Information

14.1: Online Reliability Standards Information System

The NERC Reliability Standards Staff shall maintain an electronic copy of information regarding currently proposed and currently in effect Reliability Standards. This information shall include current Reliability Standards in effect, proposed revisions to Reliability Standards, and proposed new Reliability Standards. This information shall provide a record, for at a minimum the previous five years, of the review and approval process for each Reliability Standard, including public comments received during the development and approval process.

14.2: Archived Reliability Standards Information

The NERC Staff shall maintain a historical record of Reliability Standards information that is no longer maintained online. Archived information shall be retained indefinitely as practical, but in no case less than five years or one complete standard cycle from the date on which the Reliability Standard was no longer in effect. Archived records of Reliability Standards information shall be available electronically within 30 days following the receipt by the NERC Reliability Standards Staff of a written request.

Section 15.0: Process for Updating Standard Processes

15.1: Requests to Revise the Standard Processes Manual

Any person or entity may submit a request to modify one or more of the processes contained within this manual. The Standards Committee shall oversee the handling of each request. The Standards Committee shall prioritize all requests, merge related requests, and respond to each sponsor within 30 calendar days.

The Standards Committee shall post the proposed revisions for a 45 (calendar) day formal comment period. Based on the degree of consensus for the revisions, the Standards Committee shall:

a. Submit the revised process or processes for ballot pool approval;
b. Repeat the posting for additional inputs after making changes based on comments received;
c. Remand the proposal to the sponsor for further work; or
d. Reject the proposal.

The Registered Ballot Body shall be represented by a ballot pool. The ballot procedure shall be the same as that defined for approval of a Reliability Standard, including the use of an Additional Ballot if needed. If the proposed revision is approved by the ballot pool, the Standards Committee shall submit the revised procedure to the Board for adoption. The Standards Committee shall submit to the Board a description of the basis for the changes, a summary of the comments received, and any minority views expressed in the comment and ballot process. The proposed revisions shall not be effective until approved by the NERC Board of Trustees and Applicable Governmental Authorities.

Section 16.0: Waiver

While it is NERC's intent to use its ANSI-accredited Reliability Standards development process for developing its Reliability Standards, NERC may need to develop a new or modified Reliability Standard, definition, Variance, or implementation plan under specific time constraints (such as to meet a time constrained regulatory directive) or to meet an urgent reliability issue such that there isn't sufficient time to follow all the steps in the normal Reliability Standards development process.

The Standards Committee may waive any of the provisions contained in this manual for good cause shown, but limited to the following circumstances:

- In response to a national emergency declared by the United States or Canadian government that involves the reliability of the Bulk Electric System or cyber attack on the Bulk Electric System;
- Where necessary to meet regulatory deadlines;
- Where necessary to meet deadlines imposed by the NERC Board of Trustees; or
- Where the Standards Committee determines that a modification to a proposed Reliability Standard or its Requirement(s), a modification to a defined term, a modification to an interpretation, or a modification to a variance has already been vetted by the industry through the standards development process or is so insubstantial that developing the modification through the processes contained in this manual will add significant time delay.

In no circumstances shall this provision be used to modify the requirements for achieving quorum or the voting requirements for approval of a standard.

A waiver request may be submitted to the Standards Committee by any entity or individual, including NERC committees or subgroups and NERC Staff. Prior to consideration of any waiver request, the Standards Committee must provide five business days notice to stakeholders.

Action on the waiver request will be included in the minutes of the Standards Committee. Following the approval of the Standards Committee to waive any provision of the Standard Process Manual, the Standards Committee will report this decision to the Standards Oversight and Technology Committee.[35] Actions taken pursuant to an approved waiver request will be posted on the Standard Project page and included in the next project announcement.

In addition, the Standards Committee shall report the exercise of this waiver provision to the Board of Trustees prior to adoption of the related Reliability Standard, Interpretation, definition or Variance.

Reliability Standards developed as a result of a waiver of any provision of the Standard Processes Manual shall not be filed with ANSI for approval as American National Standards.

[35] Any entity may appeal a waiver decision or any other procedural decision by the Standards Committee pursuant to Section 8.0 of the NERC Standard Processes Manual.

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
1	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 82.61% Approval: 80.73%			
2	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_in	Initial Ballot	4/25/2008	5/7/2008	Quorum: 83.01% Approval: 79.89%			
3	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 88.83% Approval: 95.43%			
4	Project 2008-07	Interpretation Request - EOP-002 - Brookfield_in	Initial Ballot	6/2/2008	6/11/2008	Quorum: 89.67% Approval: 76.47%			
5	Project 2008-04	FAC-010_FAC-011_FAC-014_Order_705_rc	Recirculation Ballot	6/13/2008	6/22/2008	Quorum: 89.36% Approval: 95.21%			
6	Project 2008-09	Request for Interpretation - EOP-001-0 - RECM_in	Initial Ballot	6/19/2008	7/2/2008	Quorum: 84.82% Approval: 85.79%			
7	Project 2007-24	Request for Interpretation - TPL-002 and TPL-003 - Ameren_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.57% Approval: 79.13%			
8	Project 2007-26	Request for Interpretation - TPL-002 and TPL-003 - MISO_rc	Recirculation Ballot	6/27/2008	7/7/2008	Quorum: 83.98% Approval: 78.31%			
9	Pre-2006	IROL Standard - IRO-010_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.71% Approval: 88.40%			
10	Pre-2006	IROL Standard - IRO-009_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.63% Approval: 89.44%			
11	Pre-2006	IROL Standard - IRO-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 92.67% Approval: 91.71%			
12	Project 2006-07	ATC et al Standard - MOD-030_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.37% Approval: 56.56%			
13	Project 2006-07	ATC et al Standard - MOD-029_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.67% Approval: 92.62%			
14	Project 2006-07	ATC et al Standard - MOD-028_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.64% Approval: 79.47%			
15	Project 2006-07	ATC et al Standard - MOD-008_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.27% Approval: 80.44%			
16	Project 2006-07	ATC et al Standard - MOD-001_in	Initial Ballot	7/21/2008	7/30/2008	Quorum: 94.02% Approval: 75.97%			
17	Project 2008-10	Request for Interpretation - CIP-006-1 - Progress Energy_in	Initial Ballot	8/7/2008	8/16/2008	Quorum: 88.18% Approval: 21.52%			
18	Pre-2006	IROL Standard - IRO-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.72% Approval: 89.49%			
19	Pre-2006	IROL Standard - IRO-009_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.68% Approval: 86.53%			
20	Pre-2006	IROL Standard - IRO-010_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 93.75% Approval: 85.95%			
21	Project 2006-07	ATC et al Standards - MOD-001_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 94.87% Approval: 76.83%			
22	Project 2006-07	ATC et al Standard - MOD-008_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.15% Approval: 81.49%			
23	Project 2006-07	ATC et al Standard - MOD-028_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.54% Approval: 79.34%			
24	Project 2006-07	ATC et al Standard - MOD-029_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.56% Approval: 92.24%			
25	Project 2006-07	ATC et al Standard - MOD-030_rc	Recirculation Ballot	8/12/2008	8/21/2008	Quorum: 95.24% Approval: 74.26%			
26	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_in	Initial Ballot	9/9/2008	9/17/2008	Quorum: 85.78% Approval: 90.37%			
27	Project 2006-07	ATC et al Standard - MOD-004_in	Initial Ballot	9/11/2008	9/21/2008	Quorum: 79.26% Approval: 66.29%			
28	Project 2007-14	Permanent Changes to CI Timing Tables_in	Initial Ballot	9/12/2008	9/22/2008	Quorum: 79.74% Approval: 100.00%			
29	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rb	Re-ballot	10/6/2008	10/24/2008	Quorum: 82.61% Approval: 74.67%			
30	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_in	Initial Ballot	10/21/2008	10/30/2008	Quorum: 83.33% Approval: 96.94%			
31	Project 2006-01	Project 2006-01 - PER-005-1_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 90.13% Approval: 82.47%			
32	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_in	Initial Ballot	10/27/2008	11/5/2008	Quorum: 89.13% Approval: 70.01%			
33	Project 2006-07	ATC et al Standard - MOD-004_rc	Recirculation Ballot	10/28/2008	11/6/2008	Quorum: 91.49% Approval: 83.71%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
34	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_in	Initial Ballot	12/1/2008	12/10/2008	Quorum: 83.77% Approval: 86.51%			
35	Project 2006-09	Project 2006-09 - FAC-008-2 - Facility Ratings_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 93.04% Approval: 57.37%			
36	Project 2008-13	Request for Interpretation - TOP-002-2 - Orlando Utilities Commission_rc	Recirculation Ballot	12/10/2008	12/19/2008	Quorum: 87.62% Approval: 97.47%			
37	Project 2006-01	Project 2006-01 - PER-005-1_rc	Recirculation Ballot	12/12/2008	12/22/2008	Quorum: 91.48% Approval: 80.63%			
38	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.15% Approval: 97.39%			
39	Project 2008-16	TOP-004-2 VSL Revisions_in	Initial Ballot	1/5/2009	1/14/2009	Quorum: 91.20% Approval: 93.93%			
40	Project 2008-11	Request for Interpretation - VAR-002-1 - ICF Consulting_rc	Recirculation Ballot	1/6/2009	1/15/2009	Quorum: 91.47% Approval: 91.21%			
41	Project 2006-07	Project 2006-07 (ATC) MOD-030-2_rc	Recirculation Ballot	1/20/2009	1/29/2009	Quorum: 85.86% Approval: 86.39%			
42	Project 2008-16	TOP-004-2 VSL Revisions_rc	Recirculation Ballot	1/28/2009	2/6/2009	Quorum: 92.59% Approval: 96.06%			
43	Project 2008-15	Request for Interpretation - CIP-006-1a - US Army COE_rc	Recirculation Ballot	2/6/2009	2/16/2009	Quorum: 93.81% Approval: 99.12%			
44	Project 2008-09	Interpretation Request - EOP-001 - R1 - RECM_in	Initial Ballot	2/27/2009	3/9/2009	Quorum: 89.67% Approval: 89.03%			
45	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_in	Initial Ballot	3/19/2009	3/30/2009	Quorum: 89.78% Approval: 92.62%			
46	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_in	Initial Ballot	4/1/2009	4/10/2009	Quorum: 91.90% Approval: 84.06%			
47	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_in	Initial Ballot	4/8/2009	4/17/2009	Quorum: 92.70% Approval: 92.71%			
48	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_in	Initial Ballot	4/14/2009	4/23/2009	Quorum: 89.81% Approval: 76.63%			
49	Project 2008-06	Project 2008-06: CIP-002-1-CIP-009-1 Revisions_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 94.37% Approval: 88.32%			
50	Project 2008-18	Project 2008-18 Interpretation-Manitoba Hydro_rc	Recirculation Ballot	4/17/2009	4/27/2009	Quorum: 95.56% Approval: 92.81%			
51	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_in	Initial Ballot	4/22/2009	5/1/2009	Quorum: 88.64% Approval: 84.77%			
52	Project 2006-03	Project 2006-03 EOP-001_EOP-005_EOP-006 System Restoration and Blackstart_rc	Recirculation Ballot	5/6/2009	5/18/2009	Quorum: 92.08% Approval: 75.39%			
53	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_in	initial Ballot	5/25/2009	6/4/2009	Quorum: 85.13% Approval: 82.10%			
54	Project 2009-11	Project 2009-11 Interpretation WECC Reliability Coordination Subcommittee IRO-10-1_rc	Recirculation Ballot	5/26/2009	6/5/2009	Quorum: 90.45% Approval: 85.76%			
55	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_in	Initial Ballot	6/1/2009	6/11/2009	Quorum: 87.10% Approval: 95.71%			
56	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_in	Initial Ballot	6/12/2009	6/22/2009	Quorum: 81.72% Approval: 94.09%			
57	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_in	Initial Ballot	6/15/2009	6/24/2009	Quorum: 87.23% Approval: 83.94%			
58	Project 2008-14	Project 2008-14 VSLs for CIP-002-1 through CIP-009-1_rc	Recirculation Ballot	7/7/2009	7/16/2009	Quorum: 92.77% Approval: 84.96%			
59	Project 2009-15	Project 2009-15 Interpretation - NYISO - MOD-001-1, MOD-029-1_rc	Recirculation Ballot	7/8/2009	7/17/2009	Quorum: 90.26% Approval: 82.25%			
60	Project 2009-08	Project 2009-08 - Nuclear Plant Interface Coordination for Order 716_rc	Recirculation Ballot	7/10/2009	7/20/2009	Quorum: 87.10% Approval: 96.94%			
61	Project 2009-10	Project 2009-10 Interpretation - CMPWG - PRC-005-1 R1_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 95.26% Approval: 95.62%			
62	Project 2009-14	Project 2009-14 Interpretation - PacifiCorp - TPL-002-0a_rc	Recirculation Ballot	7/24/2009	8/6/2009	Quorum: 91.24% Approval: 98.85%			
63	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 90.46%			
64	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.40% Approval: 89.14%			
65	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.32% Approval: 88.26%			
66	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.16% Approval: 90.15%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
67	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 85.71% Approval: 88.63%			
68	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.64% Approval: 87.63%			
69	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.50% Approval: 85.78%			
70	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 86.28% Approval: 89.56%			
71	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 87.98% Approval: 87.31%			
72	Project 2009-17	Project 2009-17 Interpretation - Y-W Electric and Tri-State - PRC-004-1 and PRC-005-1_in	Initial Ballot	7/31/2009	8/10/2009	Quorum: 90.32% Approval: 62.15%			
73	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rb	Re-ballot	7/27/2009	8/14/2009	Quorum: 84.65% Approval: 74.79%			
74	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_in	Initial Ballot	8/6/2009	8/17/2009	Quorum: 84.68% Approval: 68.92%			
75	Project 2007-23	Project 2007-23 TPL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 89.28%			
76	Project 2007-23	Project 2007-23 BAL Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.04% Approval: 89.41%			
77	Project 2007-23	Project 2007-23 CIP, COM, and VAR Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.41% Approval: 84.64%			
78	Project 2007-23	Project 2007-23 FAC and MOD Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.67% Approval: 88.04%			
79	Project 2007-23	Project 2007-23 INT, PER, and NUC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.17% Approval: 88.73%			
80	Project 2007-23	Project 2007-23 IRO Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 91.96% Approval: 90.77%			
81	Project 2007-23	Project 2007-23 PRC Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.31% Approval: 86.93%			
82	Project 2007-23	Project 2007-23 TOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.11% Approval: 88.26%			
83	Project 2008-08	Project 2008-08 EOP Violation Severity Levels_rc	Recirculation Ballot	8/17/2009	8/27/2009	Quorum: 92.70% Approval: 85.80%			
84	Order 706-B	Order 706-B Nuclear Implementation Plan_in	Initial Ballot	8/19/2009	8/28/2009	Quorum: 81.96% Approval: 97.37%			
85	Project 2008-07	Request for Interpretation - Brookfield Power - EOP-002_rc	Recirculation Ballot	8/20/2009	8/31/2009	Quorum: 86.96% Approval: 70.85%			
86	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.68% Approval: 80.37%			
87	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 84.92% Approval: 79.04%			
88	Project 2009-18	Project 2009-18 - Withdraw Three Midwest ISO Waivers_in	Initial Ballot	8/27/2009	9/8/2009	Quorum: 85.28% Approval: 99.62%			
89	Order 706-B	Order 706-B Nuclear Implementation Plan_rc	Recirculation Ballot	9/1/2009	9/10/2009	Quorum: 87.11% Approval: 97.18%			
90	RSDP V7	Reliability Standards Development Procedure - Version 7 - June 2009_rc	Recirculation Ballot	9/2/2009	9/14/2009	Quorum: 86.31% Approval: 76.09%			
91	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_in	Initial Ballot	9/10/2009	9/21/2009	Quorum: 87.45% Approval: 94.18%			
92	Project 2009-16	Project 2009-16 - Interpretation - WECC - CIP-007-1_in	Initial Ballot	9/9/2009	9/21/2009	Quorum: 85.31% Approval: 100.00%			
93	Project 2006-04	Project 2006-04 - Back-up Facilities - EOP-008-1_in	Initial Ballot	9/16/2009	9/28/2009	Quorum: 82.69% Approval: 72.86%			
94	Project 2009-09	Project 2009-09 - Interpretation - Covanta Energy - CIP-001-1_rc	Recirculation Ballot	9/29/2009	10/9/2009	Quorum: 89.92% Approval: 68.31%			
95	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 Revised R1 for Progress Energy	Initial Ballot	9/30/2009	10/12/2009	Quorum: 79.92% Approval: 74.47%			
96	Project 2009-12	Project 2009-12 - Interpretation - PacifiCorp - CIP-005-1_rc	Recirculation Ballot	10/16/2009	10/26/2009	Quorum: 86.29% Approval: 83.25%			
97	Project 2008-06	Project 2008-06 Cyber Security (VRFs and VSLs for Version 2 CIP Standards)_rc	Recirculation Ballot	11/2/2009	11/12/2009	Quorum: 88.70% Approval: 94.24%			
98	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 2_in	Initial Ballot	11/5/2009	11/16/2009	Quorum: 85.97% Approval: 98.07%			
99	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_in	Initial Ballot	11/20/2009	11/30/2009	Quorum: 89.58% Approval: 88.07%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
100	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 1)_in	Initial Ballot	11/19/2009	12/7/2009	Quorum: 85.83% Approval: 58.91%			
101	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._in	Initial Ballot	11/20/2009	12/7/2009	Quorum: 87.11% Approval: 93.40%			
102	Project 2009-21	Project 2009-21 - Cyber Security Ninety-day Response_rc	Recirculation Ballot	12/3/2009	12/14/2009	Quorum: 93.33% Approval: 85.55%			
103	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers_in	Initial Ballot	12/1/2009	12/14/2009	Quorum: 86.13% Approval: 72.11%			
104	Project 2009-13	Project 2009-13 - Interpretation - PacifiCorp - CIP-006-1_rc	Recirculation Ballot	12/11/2009	12/23/2009	Quorum: 90.08% Approval: 78.77%			
105	Project 2009-24	Project 2009-24 - Interpretation - FMPA - EOP-005-1_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 87.68% Approval: 17.79%			
106	Project 2009-25	Project 2009-25 - Interpretation - BPA - BAL-001-01.a and BAL-002-0_in	Initial Ballot	1/5/2010	1/15/2010	Quorum: 88.00% Approval: 34.28%			
107	Project 2009-26	Project 2009-26 - Interpretation - WECC - CIP-004-1_in	Initial Ballot	1/6/2010	1/19/2010	Quorum: 84.21% Approval: 42.24%			
108	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Initial Ballot	1/12/2010	1/22/2010	Quorum: 89.16% Approval: 75.16%			
109	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 84.98% Approval: 90.82%			
110	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_in	Initial Ballot	2/10/2010	2/22/2010	Quorum: 87.36% Approval: 91.79%			
111	Project 2009-29	Project 2009-29 - Interpretation - TOP-002-2a for FMPP_in	Initial Ballot	2/11/2010	2/22/2010	Quorum: 84.34% Approval: 84.56%			
112	Project 2009-19	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.83% Approval: 48.60%			
113	Project 2009-20	Project 2009-20 - Interpretation - BAL-003-0 - Energy Mark, Inc._rc	Recirculation Ballot	2/16/2010	2/26/2010	Quorum: 92.44% Approval: 91.90%			
114	Project 2009-30	Project 2009-30 - Interpretation - PRC-001-1 for WPSC_in	Initial Ballot	2/15/2010	2/26/2010	Quorum: 89.51% Approval: 48.74%			
115	Project 2006-02	Project 2006-02 - Assess Transmission Future Needs - TPL-001-1_in	Initial Ballot	2/19/2010	3/1/2010	Quorum: 91.38% Approval: 35.36%			
116	Project 2009-31	Project 2009-31 - Interpretation - TOP-001-1 for FMPP_in	Initial Ballot	3/3/2010	3/16/2010	Quorum: 88.24% Approval: 98.27%			
117	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-2	Recirculation Ballot	3/8/2010	3/18/2010	Quorum: 93.71% Approval: 78.15%			
118	Project 2009-32	Project 2009-32 - Interpretation - EOP-003-1 for FMPP_rb	Re-ballot	3/10/2010	3/31/2010	Quorum: 91.37% Approval: 77.66%			
119	Project 2009-23	Project 2009-23 - Interpretation - CIP-004-2 - U.S. Army Corps of Engineers (Revision 1)_in	Initial Ballot	3/29/2010	4/8/2010	Quorum: 88.52% Approval: 63.43%			
120	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_in	Initial Ballot	4/15/2010	4/26/2010	Quorum: 81.97% Approval: 98.64%			
121	SPM	Standards Process Manual Revisions_in	Initial Ballot	4/19/2010	4/29/2010	Quorum: 87.82% Approval: 80.48%			
122	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_in	Initial Ballot	4/28/2010	5/10/2010	Quorum: 83.15% Approval: 74.55%			
123	SPM	Standards Process Manual Revisions_rc	Recirculation Ballot	4/30/2010	5/10/2010	Quorum: 93.73% Approval: 86.69%			
124	Project 2010-11	Project 2010-11 SAR for TPL Table 1 Order_in	Initial Ballot	5/17/2010	5/27/2010	Quorum: 84.41% Approval: 63.75%			
125	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_in	Initial Ballot	5/19/2010	6/1/2010	Quorum: 84.83% Approval: 90.83%			
126	Project 2010-09	Project 2010-09: NUC Implementation Plans for CIP Version 2 and Version 3_rc	Recirculation Ballot	6/22/2010	7/2/2010	Quorum: 89.10% Approval: 87.24%			
127	Project 2006-04	Project 2006-04 - Backup Facilities - Revision 1_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 89.05% Approval: 79.45%			
128	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_in	Initial Ballot	6/23/2010	7/6/2010	Quorum: 87.04% Approval: 84.98%			
129	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Initial Ballot	7/7/2010	7/17/2010	Quorum: 86.94% Approval: 43.13%			
130	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Initial Ballot	7/8/2010	7/17/2010	Quorum:91.12 % Approval: 22.91%			
131	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	7/8/2010	7/17/2010	Quorum: 86.00% Approval: 28.00%			
132	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: Protection System definition	Initial Ballot	7/8/2010	7/17/2010	Quorum: 87.85% Approval: 39.35%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
133	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Initial Ballot	7/9/2010	7/19/2010	Quorum: 86.18% Approval: 65.93%			
134	Project 2006-04	Prokect 2006-04 - Backup Facilities - Revision 1_rc	Recirculation Ballot	7/16/2010	7/26/2010	Quorum: 93.43% Approval: 85.22%			
135	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	7/23/2010	8/2/2010	Quorum: 94.70% Approval: 58.61%			
136	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	7/24/2010	8/3/2010	Quorum: 92.99% Approval: 49.61%			
137	Project 2006-08	Project 2006-08 - Reliability Coordination - Transmission Loading Relief_rc	Recirculation Ballot	8/20/2010	8/30/2010	Quorum: 88.26% Approval: 93.93%			
138	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Initial Ballot	9/14/2010	9/24/2010	Quorum: 92.73% Approval: 79.17%			
139	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3	Initial Ballot	9/17/2010	9/27/2010	Quorum: 96.46% Approval: 21.77%			
140	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Successive Ballot	9/24/2010	10/4/2010	Quorum: 85.71% Approval: 81.72%			
141	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Successive Ballot	10/2/2010	10/14/2010	Quorum: 84.11% Approval: 84.52%			
142	Project 2008-09	Project 2008-09 - Interpretation - RECM - Revision 3_rc	Recirculation Ballot	10/4/2010	10/14/2010	Quorum: 88.11% Approval: 99.14%			
143	Project 2009-28	Project 2009-28 - Interpretation - EOP-001-1 and EOP-001-2 for FMPP_rc	Recirculation Ballot	10/5/2010	10/15/2010	Quorum: 92.19% Approval: 94.78%			
144	Project 2009-27	Project 2009-27 - Interpretation - TOP-002-2a for FMPAA_rc	Recirculation Ballot	10/6/2010	10/16/2010	Quorum: 91.21% Approval: 93.44%			
145	Project 2007-01	Project 2007-01 Underfrequency Load Shedding: PRC-006-1 and EOP-003-1	Recirculation Ballot	10/18/2010	10/28/2010	Quorum: 89.84% Approval: 84.67%			
146	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 93.66% Approval: 43.33%			
147	Project 2010-10	Project 2010-10 FAC-013-2 Planning Transfer Capability_in	Initial Ballot	10/20/2010	11/3/2010	Quorum: 88.54% Approval: 39.85%			
148	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_in	Initial Ballot	10/28/2010	11/7/2010	Quorum: 81.61% Approval: 93.72%			
149	Project 2007-17	Project 2007-17 Protection System Maintenance: Protection System definition	Recirculation Ballot	11/1/2010	11/11/2010	Quorum: 89.41% Approval: 86.83%			
150	2010 SPM	2010 Standard Processes Manual (Proposed Changes)_rc	Recirculation Ballot	11/9/2010	11/13/2010	Quorum: 87.00% Approval: 92.88%			
151	Project 2009-17	Project 2009-17 - Interpretation Y-W Electric and Tri-State (Revision 2)_rc	Recirculation Ballot	11/19/2010	12/3/2010	Quorum: 87.81% Approval: 82.41%			
152	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_in	Initial Ballot	12/1/2010	12/10/2010	Quorum: 87.07% Approval: 77.06%			
153	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-3	Initial Ballot	12/2/2010	12/11/2010	Quorum: 84.46% Approval: 42.89%			
154	Project 2007-04	Project 2007-04 - Certifying System Operators: PER-003-1	Recirculation Ballot	12/2/2010	12/13/2010	Quorum: 95.50% Approval: 86.91%			
155	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Initial Ballot	12/7/2010	12/16/2010	Quorum: 88.00% Approval: 51.51%			
156	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Successive Ballot	12/10/2010	12/20/2010	Quorum: 79.88% Approval: 44.65%			
157	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005-2	Non-binding Poll	12/10/2010	12/20/2010	Quorum: 78.00% Approval: 53.00%			
158	Project 2008-06	Project 2008-06 Cyber Security 706 (Version 4 CIP Standards)_sb_rc	Recirculation Ballot	12/20/2010	12/30/2010	Quorum: 90.49% Approval: 80.56%			
159	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_in	Recirculation Ballot	12/27/2010	1/5/2011	Quorum: 90.42% Approval: 83.33%			
160	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 22.09%	Oppose 12/16/11		
161	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.62% Approval: 33.49%	Oppose 12/16/11		
162	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 26.82%	Oppose 12/16/11		
163	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.60% Approval: 28.04%	Oppose 12/16/11		
164	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.60%	Oppose 12/16/11		
165	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 24.15%	Oppose 12/16/11		

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166	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 94.02% Approval: 34.30%	Oppose 12/16/11		
167	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 27.28%	Oppose 12/16/11		
168	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 26.61%	Oppose 12/16/11		
169	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Initial Ballot	12/16/2011	1/6/2011	Quorum: 93.61% Approval: 29.88%	Oppose 12/16/11		
170	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.15% Approval: 42.06%	Oppose 12/16/11		
171	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Initial Ballot	12/16/2011	1/6/2011	Quorum: 92.56% Approval: 25.34%	Oppose 12/16/11		
172	Project 2010-10	Project 2010-10: FAC Order 729_in	Initial Ballot	12/30/2010	1/8/2011	Quorum: 83.23% Approval: 58.16%			
173	Project 2010-10	Project 2010-10: FAC Order 729_rc	Recirculation Ballot	1/14/2011	1/23/2011	Quorum: 86.65% Approval: 68.98%			
174	Project 2010-11	Project 2010-11 TPL Table 1 Footnote B SAR_rc	Recirculation Ballot	1/26/2011	2/5/2011	Quorum: 93.29% Approval: 86.79%	Support 1/5/11		
175	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Successive Ballot	1/24/2011	2/14/2011	Quorum: 83.95% Approval: 65.71%	Support 2/11/11		
176	Project 2007-23	Project 2007-23 - Violation Severity Levels	Non-binding Poll	2/9/2011	2/22/2011	Quorum: 78.00% Approval: 72.00%	Support 10/28/10		
177	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Successive Ballot	2/18/2011	2/28/2011	Quorum: 79.28% Approval: 79.34%	Support 2/22/11		
178	Project 2010-13	Project 2010-13 - Relay Loadability Order - PRC-023	Recirculation Ballot	2/24/2011	3/6/2011	Quorum: 87.35% Approval: 68.83%	Support 2/11/11		
179	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	Initial Ballot	2/25/2011	3/7/2011	Quorum: 87.10% Approval: 49.54%	Support 3/2/11		
180	Project 2010-15	Project 2010-15 - Expedited Action Revisions to CIP-005-4	Successive Ballot	4/19/2011	4/28/2011	Quorum: 79.66% Approval: 38.00%	Oppose 4/19/11		
181	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Initial Ballot	4/21/2011	5/2/2011	Quorum: 86.01% Approval: 48.74%	Abstain 4/26/11		
182	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Non-binding Poll	4/21/2011	5/2/2011	Quorum: 75.58% Approval: 73.00%			
183	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Successive Ballot	5/3/2011	5/12/2011	Quorum: 78.33% Approval: 67.00%	No Recommendation		
184	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	5/3/2011	5/12/2011	Quorum: 75.00% Approval: 66.00%			
185	Project 2009-06	Project 2009-06 - Facility Ratings: FAC-008-3	Recirculation Ballot	5/12/2011	5/23/2011	Quorum: 91.25% Approval: 78.92%	Support 5/12/11		
186	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Successive Ballot	5/18/2011	5/31/2011	Quorum: 92.07% Approval: 73.99%			
187	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs - TPL-001 through TPL-006	Non-binding Poll	5/18/2011	5/31/2011	Quorum: 86.79% Approval: 71.9%			
188	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Initial Ballot	5/31/2011	6/9/2011	Quorum: 88.47% Approval: 48.64%	Oppose 5/31/11		
189	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2, TOP-002-2 and TOP-003-2	Non-binding Poll	5/31/2011	6/9/2011	Quorum: 84.18% Approval: 41.00%			
190	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Recirculation Ballot	6/20/2011	6/30/2011	Quorum: 82.97% Approval: 64.76%	Support 6/28/11		
191	Project 2007-17	Project 2007-17 – Protection System Maintenance and Testing – PRC-005	Non-binding Poll	6/20/2011	6/30/2011	Quorum: 52.63% Approval: 60.00%			
192	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	Recirculation Ballot	7/13/2011	7/22/2011	Quorum: 94.33% Approval: 75.37%			
193	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.99%	Support 7/22/11		
194	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 75.17%	Support 7/22/11		
195	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Recirculation Ballot	7/15/2011	7/25/2011	Quorum: 94.13% Approval: 76.27%	Support 7/22/11		
196	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-002-3	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 93.00%			
197	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-005-4	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.66% Approval: 93.00%			
198	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-014-2	Non-binding Poll	7/15/2011	7/25/2011	Quorum: 75.37% Approval: 89.00%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
199	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.25% Approval: 46.53%	No Consensus 7/28/11		
200	Project 2007-09	Project 2007-09 – Generator Verification: MOD-026-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.75% Approval: 56.00%			
201	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Initial Ballot	7/22/2011	8/1/2011	Quorum: 90.82% Approval: 18.23%	No Consensus 7/28/11		
202	Project 2007-09	Project 2007-09 – Generator Verification: PRC-024-1	Non-binding Poll	7/22/2011	8/1/2011	Quorum: 88.35% Approval: 20.79%			
203	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Initial Ballot	9/19/2011	9/29/2011	Quorum: 84.86% Approval: 61.10%	Support 9/21/11		
204	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing: PRC-005	Non-binding Poll	9/19/2011	9/29/2011	Quorum: 83.13% Approval: 68.68%			
205	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Definition of BES	Initial Ballot	9/30/2011	10/10/2011	Quorum: 92.97% Approval: 71.68%	No Consensus 10/3/11		
206	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Initial Ballot	9/30/2011	10/10/2011	Quorum: 89.53% Approval: 64.03%	No Consensus 10/7/111		
207	Project 2007-07	Project 2007-07 Vegetation Management: FAC-003-2	Recirculation Ballot	10/4/2011	10/13/2011	Quorum: 87.17% Approval: 86.25%	Support 2/22/11		
208	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Initial Ballot	11/7/2011	11/16/2011	Quorum: 88.05% Approval: 85.53%	Support 11/8/11		
209	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Initial Ballot	11/8/2011	11/17/2011	Quorum: 91.20% Approval: 95.05%	Support 11/8/11		
210	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 88.22% Approval: 86.94%	Support 11/10/11		
211	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Initial Ballot	11/9/2011	11/18/2011	Quorum: 85.08% Approval: 85.71%	Support 11/10/11		
212	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.82% Approval: 85.31%	Support 11/10/11		
213	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1	Initial Ballot	11/9/2011	11/18/2011	Quorum: 84.29% Approval: 96.09%	Support 11/10/11		
214	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Successive Ballot	11/11/2011	11/21/2011	Quorum: 83.53% Approval: 95.99%	Support 11/14/11		
215	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System and Implementation Plan	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 95.92% Approval: 81.32%	Support 10/3/11		
216	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System: Detailed Information to Support BES Exceptions Request	Recirculation Ballot	11/10/2011	11/21/2011	Quorum: 93.02% Approval: 81.48%	Support 10/3/11		
217	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Initial Ballot	11/30/2011	12/9/2011	Quorum: 93.92% Approval: 30.82%	Oppose 12/5/11		
218	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Non-binding Poll	11/30/2011	12/9/2011	Quorum: 89.49% Approval: 36.00%			
219	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Initial Ballot	12/2/2011	12/12/2011	Quorum: 87.97% Approval: 36.21%	Oppose 12/5/11		
220	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	12/2/2011	12/12/2011	Quorum: 85.28% Approval: 45.00%			
221	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-x R1 for Progress Energy	Recirculation Ballot	12/9/2011	12/19/2011	Quorum: 88.02% Approval: 96.04%	Support 11/14/11		
222	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	Recirculation Ballot	12/12/2011	12/22/2011	Quorum: 90.10% Approval: 92.49%	Support 11/8/11		
223	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 92.00% Approval: 94.58%	Support 11/8/11		
224	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 88.48% Approval: 90.10%	Support 11/10/11		
225	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 87.17% Approval: 85.38%	Support 11/10/11		
226	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.91% Approval: 85.03%	Support 11/10/11		
227	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-004-2.1a	Recirculation Ballot	12/14/2011	12/23/2011	Quorum: 86.65% Approval: 96.43%	Support 11/10/11		
228	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 59.93%	Oppose 1/9/12		
229	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 77.08 %	Support 1/9/12		
230	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	1/3/2012	1/12/2012	Quorum: 82.04% Approval: 78.95%	Support 1/9/12		
231	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-001-1	Non-binding Poll	1/4/2012	1/13/2012	Quorum: 78.27% Approval: 93.00%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
232	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Non-binding Poll	1/9/2012	1/18/2012	Quorum: 76.41% Approval: 71.42%			
233	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 67.61%			
234	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	1/9/2012	1/19/2012	Quorum: 81.50% Approval: 70.28%			
235	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 54.64%	Oppose 2/7/12		
236	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 82.11% Approval: 80.62%	Support 2/7/12		
237	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Successive Ballot	1/30/2012	2/9/2012	Quorum: 81.82% Approval: 80.21%	Support 2/7/12		
238	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.35% Approval: 71.35%			
239	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 80.06% Approval: 90.86%			
240	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	1/30/2012	2/9/2012	Quorum: 79.77% Approval: 84.69%			
241	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Successive Ballot	3/14/2012	3/23/2012	Quorum: 88.55% Approval: 79.61%	Support 3/16/12		
242	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Initial Ballot	3/14/2012	3/23/2012	Quorum: 89.63% Approval: 94.71%	Support 3/16/12		
243	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR-002 for Constellation	Initial Ballot	3/14/2012	3/23/2012	Quorum: 86.92% Approval: 63.09%	Support 3/16/12		
244	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 81.45% Approval: 61.21%			
245	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	3/19/2012	3/29/2012	Quorum: 80.38% Approval: 41.09%			
246	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	3/19/2012	3/29/2012	Quorum: 84.32% Approval: 73.93%	Support 3/19/12		
247	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	3/19/2012	3/29/2012	Quorum: 81.93% Approval: 66.12%			
248	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.37% Approval: 85.18%	Support 4/5/12		
249	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Successive Ballot	3/30/2012	4/9/2012	Quorum: 80.10% Approval: 85.01%	Support 4/5/12		
250	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.28% Approval: 41.09%	Oppose 4/16/12		
251	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 36.84%	Oppose 4/16/12		
252	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.04% Approval: 48.70%%	Oppose 4/16/12		
253	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.82% Approval: 43.72%			
254	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.04% Approval: 38.56%			
255	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	4/6/2012	4/16/2012	Quorum: 86.53% Approval: 46.38%			
256	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1a	Initial Ballot	4/6/2012	4/16/2012	Quorum: 88.95% Approval: 92.41%	Support 4/16/12		
257	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28%% Approval: 75.44%			
258	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.02% Approval: 87.22%			
259	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Successive Ballot	4/11/2012	4/20/2012	Quorum: 78.28% Approval: 80.11%			
260	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.21% Approval: 69.84%			
261	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Non-binding Poll	4/11/2012	4/23/2012	Quorum: 77.48% Approval: 67.64%			
262	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 by WECC	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 90.96% Approval: 80.08%	Support 3/16/12		
263	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Recirculation Ballot	4/20/2012	4/30/2012	Quorum: 92.68% Approval: 94.61%	Support 3/16/12		
264	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-3	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.72% Approval: 87.34%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
265	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: FAC-003-X	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 81.94% Approval: 87.32%			
266	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface: PRC-005-1.1b	Recirculation Ballot	4/24/2012	5/3/2012	Quorum: 90.44% Approval: 93.23%			
267	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-001-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 76.84%	Abstain 4/19/12		
268	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-002-3	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 88.11%	Support 4/19/12		
269	Project 2007-03	Project 2007-03 - Real-time Operations: TOP-003-2	Recirculation Ballot	4/27/2012	5/6/2012	Quorum: 79.36% Approval: 80.79%	Support 4/19/12		
270	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.63% Approval: 37.37%	Abstain 5/17/12		
271	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.45% Approval: 60.55%	Abstain 5/17/12		
272	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.40% Approval: 38.81%	Abstain 5/17/12		
273	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.98% Approval: 55.08%	Abstain 5/17/12		
274	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.22% Approval: 38.50%	Abstain 5/17/12		
275	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 45.78%	Abstain 5/17/12		
276	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.19% Approval: 67.19%	Abstain 5/17/12		
277	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	5/11/2012	5/21/2012	Quorum: 87.01% Approval: 60.19%	Abstain 5/17/12		
278	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 47.92%	Abstain 5/17/12		
279	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	5/11/2012	5/21/2012	Quorum: 86.39% Approval: 58.23%	Abstain 5/17/12		
280	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	5/11/2012	5/21/2012	Quorum: 85.12% Approval: 66.23%	Abstain 5/17/12		
281	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	5/11/2012	5/21/2012	Quorum: 84.09% Approval: 47.88%	Abstain 5/17/12		
282	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	5/15/2012	5/24/2012	Quorum: 84.43% Approval: 46.18%			
283	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	5/15/2012	5/24/2012	Quorum: 79.95% Approval: 52.67%			
284	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Initial Ballot	6/11/2012	6/20/2012	Quorum: 84.14% Approval: 21.11%	Oppose 6/13/12		
285	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	6/11/2012	6/20/2012	Quorum: 81.01% Approval: 28.30%			
286	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	6/18/2012	6/27/2012	Quorum: 79.46% Approval: 79.00%			
287	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Non-binding Poll	6/18/2012	6/27/2012	Quorum: 75.00% Approval: 70.21%			
288	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Successive Ballot	6/18/2012	6/27/2012	Quorum: 85.98% Approval: 68.22%	Support 6/26/12		
289	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Initial Ballot	6/26/2012	7/5/2012	Quorum: 84.24% Approval: 23.82%	Oppose 6/27/12		
290	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	6/26/2012	7/5/2012	Quorum: 82.26% Approval: 25.19%			
291	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.34% Approval: 81.71%			
292	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Recirculation Ballot	6/27/2012	7/6/2012	Quorum: 85.04% Approval: 81.72%			
293	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-002-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 84.16% Approval: 79.16%			
294	Project 2006-06	Project 2006-06 - Reliability Coordination - IRO-001-3	Non-binding Poll	6/27/2012	7/6/2012	Quorum: 83.87% Approval: 86.91%			
295	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Successive Ballot	6/27/2012	7/9/2012	Quorum: 75.37% Approval: 72.16%	No Consensus 7/5/12		
296	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Non-binding Poll	6/27/2012	7/11/2012	Quorum: 75.37% Approval: 73.71%			
297	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Recirculation Ballot	7/18/2012	7/27/2012	Quorum: 90.97% Approval: 69.81%	Support 6/26/12		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
298	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision of VAR-002 for Constellation	Non-binding Poll	7/18/2012	7/27/2012	Quorum: 81.31% Approval: 60.93%			
299	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Initial Ballot	7/20/2012	7/30/2012	Quorum: 80.39% Approval: 79.28%	Oppose 7/20/12		
300	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Non-binding Poll	7/20/2012	7/30/2012	Quorum: 78.26% Approval: 76.07%			
301	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Initial Ballot	7/24/2012	8/2/2012	Quorum: 83.11% Approval: 54.16%	Oppose 7/20/12		
302	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Successive Ballot	8/17/2012	8/27/2012	Quorum: 78.11% Approval: 80.31%	Support 6/22/12		
303	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group	Successive Ballot	8/23/2012	9/4/2012	Quorum: 79.21% Approval: 87.78%	Support 2/22/10		
304	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Initial Ballot	8/29/2012	9/7/2012	Quorum: 86.71% Approval: 37.68%	Support 9/5/12		
305	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	8/29/2012	9/7/2012	Quorum: 84.17% Approval: 37.36%			
306	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001-2	Recirculation Ballot	9/6/2012	9/17/2012	Quorum: 80.35% Approval: 75.01%			
307	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols	Successive Ballot	9/11/2012	9/20/2012	Quorum: 77.70% Approval: 50.57%	Support 9/15/12		
308	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	9/11/2012	9/20/2012	Quorum: 84.05% Approval: 54.07%			
309	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Recirculation Ballot	9/12/2012	9/21/2012	Quorum: 85.36% Approval: 87.34%			
310	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Successive Ballot	9/18/2012	9/27/2012	Quorum: 78.54% Approval: 63.40%	No Consensus 9/27/12		
311	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	9/18/2012	9/27/2012	Quorum: 78.93% Approval: 71.04%			
312	Project 2009-19	Project 2009-19 - Interpretation of BAL-002-0 NWPP Reserve Sharing Group	Recirculation Ballot	9/28/2012	10/8/2012	Quorum: 85.11% Approval: 90.34%	Support 2/22/10		
313	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 74.85%	Support 10/4/12		
314	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.37% Approval: 89.50%	Support 10/4/12		
315	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 85.58%	Support 10/4/12		
316	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 89.46%	Support 10/4/12		
317	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.11%	Support 10/4/12		
318	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 87.73%	Support 10/4/12		
319	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.74%	Support 10/4/12		
320	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 91.73%	Support 10/4/12		
321	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 84.60%	Support 10/4/12		
322	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Successive Ballot	10/1/2012	10/10/2012	Quorum: 80.58% Approval: 92.90%	Support 10/4/12		
323	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation	Successive Ballot	10/1/2012	10/10/2012	Quorum: 78.93% Approval: 94.00%	Support 10/4/12		
324	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Successive Ballot	10/1/2012	10/10/2012	Quorum: 79.13% Approval: 91.59%	Support 10/4/12		
325	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Initial Ballot	10/3/2012	10/12/2012	Quorum: 87.50% Approval: 63.25%	Support 10/4/12		
326	VRFs and VSLs	Revisions to Outstanding VRFs and VSLs	Non-binding Poll	10/10/2012	10/23/2012	Quorum: 78.57% Approval: 73.02%			
327	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing: PRC-005	Recirculation Ballot	10/15/2012	10/24/2012	Quorum: 81.08% Approval: 80.51%	Support 6/22/12		
328	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.55% Approval: 76.50%			
329	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 75.00% Approval: 57.24%			
330	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Successive Ballot	10/19/2012	10/31/2012	Quorum: 83.61% Approval: 68.31%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
331	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.34% Approval: 71.53%			
332	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Successive Ballot	10/19/2012	10/31/2012	Quorum: 82.07% Approval: 70.64%			
333	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.88% Approval: 77.10%			
334	Project 2007-09	Project 2007-09 Generator Verification: PRC-024-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 75.40% Approval: 52.72%			
335	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 77.94% Approval: 64.24%			
336	Project 2007-09	Project 2007-09 Generator Verification: MOD-027-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.06% Approval: 68.93%			
337	Project 2007-09	Project 2007-09 Generator Verification: PRC-019-1	Non-binding Poll	10/19/2012	10/31/2012	Quorum: 78.51% Approval: 63.63%			
338	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-002-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 78.59%	Support 10/4/12		
339	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-003-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 92.75%	Support 10/4/12		
340	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-004-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 89.73%	Support 10/4/12		
341	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-005-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 93.73%	Support 10/4/12		
342	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-006-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.53%	Support 10/4/12		
343	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-007-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 91.79%	Support 10/4/12		
344	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-008-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.47%	Support 10/4/12		
345	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-009-5	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.33% Approval: 94.60%	Support 10/4/12		
346	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-010-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 88.99%	Support 10/4/12		
347	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP-011-1	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 85.54% Approval: 95.67%	Support 10/4/12		
348	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Implementation Plan	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 94.91%	Support 10/4/12		
349	Project 2008-06	Project 2008-06 - Cyber Security - Order 706: CIP V5 Definitions	Recirculation Ballot	10/26/2012	11/5/2012	Quorum: 83.47% Approval: 93.23%	Support 10/4/12		
350	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Recirculation Ballot	10/24/2012	11/5/2012	Quorum: 85.14% Approval: 71.39%			
351	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting: EOP-004-2	Non-binding Poll	10/24/2012	11/5/2012	Quorum: 78.93% Approval: 71.04%			
352	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Successive Ballot	10/26/2012	11/6/2012	Quorum: 82.04% Approval: 76.08%	Support 11/5/12		
353	Project 2010-11	Project 2010-11 TPL footnote b Initial Ballot October 2012 in	Initial Ballot	11/9/2012	11/19/2012	Quorum: 80.45% Approval: 56.18%			
354	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Initial Ballot	11/26/2012	12/5/2012	Quorum: 84.81% Approval: 72.57%	Oppose 12/5/12		
355	Project 2013-02	Project 2013-02 - Paragraph 81	Initial Ballot	11/30/2012	12/10/2012	Quorum: 75.77% Approval: 96.45%	Support 12/10/12		
356	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	12/4/2012	12/13/2012	Quorum: 76.78% Approval: 53.57%	No Consensus 12/13/12		
357	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	12/4/2012	12/13/2012	Quorum: 77.22% Approval: 57.91%			
358	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Successive Ballot	12/7/2012	12/17/2012	Quorum: 76.47% Approval: 33.23%	Oppose 12/17/12		
359	Project 2007-06	Project 2007-06 - System Protection Coordination: PRC-027-1	Non-binding Poll	12/7/2012	12/17/2012	Quorum: 75.58% Approval: 34.80%			
360	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Initial Ballot	12/11/2012	12/20/2012	Quorum: 84.50% Approval: 95.60%	Support 12/19/12		
361	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Successive Ballot	12/11/2012	12/20/2012	Quorum: 83.24% Approval: 84.48%	Support 12/19/12		
362	Project 2007-09	Project 2007-09 Generator Verification: MOD-025-2	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.89% Approval: 73.06%			
363	Project 2007-09	Project 2007-09 Generator Verification: MOD-026-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 79.00% Approval: 79.36%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
364	Project 2007-09	Project 2007-09_Generator Verification: MOD-027-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.68% Approval: 74.27%			
365	Project 2007-09	Project 2007-09_Generator Verification: PRC-019-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 85.87% Approval: 73.63%			
366	Project 2007-12	Project 2007-12 - Frequency Response: BAL-003-1	Recirculation Ballot	12/12/2012	12/21/2012	Quorum: 86.19% Approval: 76.53%			
367	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	1/2/2013	1/11/2013	Quorum: 78.16% Approval: 60.31%	Support 1/11/13		
368	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	Non-binding Poll	1/2/2013	1/11/2013	Quorum: 76.38% Approval: 55.68%			
369	Project 2010-11	Project 2010-11 Successive Ballot December 2012_in	Successive Ballot	1/2/2013	1/11/2013	Quorum: 85.47% Approval: 65.77%	No Consensus 1/11/13		
370	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Initial Ballot	1/4/2013	1/14/2013	Quorum: 83.94% Approval: 21.80%	Oppose 1/11/13		
371	Project 2010-14.1	Project 2010-14.1_- Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-012-1	Non-binding Poll	1/4/2013	1/14/2013	Quorum: 82.23% Approval: 24.27%			
372	Project 2013-02	Project 2013-02 - Paragraph 81	Recirculation Ballot	1/8/2013	1/17/2013	Quorum: 84.60% Approval: 95.22%	Support 12/10/12		
373	Project 2012-INT-05	Interpretation 2012-INT-05: CIP-002-3 for OGE	Recirculation Ballot	1/14/2013	1/23/2013	Quorum: 87.13% Approval: 99.09%	Support 12/19/12		
374	SPM-SPIG	Standard Processes Manual Revisions to Implement SPIG Recommendations	Recirculation Ballot	1/18/2013	1/28/2013	Quorum: 85.90% Approval: 85.57%	Support 12/19/12		
375	Project 2010-11	Project 2010-11 Recirculation Ballot Jan 2013_in	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 88.55% Approval: 69.63%	No Consensus 1/11/13		
376	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Recirculation Ballot	1/22/2013	1/31/2013	Quorum: 85.67% Approval: 77.61%	Oppose 12/5/12		
377	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Successive Ballot	2/11/2013	2/20/2013	Quorum: 77.62% Approval: 50.66%	Support 9/5/12		
378	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Non-binding Poll	2/11/2013	2/20/2013	Quorum: 75.38% Approval: 50.60%			
379	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Successive Ballot	2/15/2013	2/28/2013	Quorum: 78.80% Approval: 89.01%	Support 1/11/13		
380	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Non-binding Poll	2/15/2013	2/28/2013	Quorum: 76.38% Approval: 84.24%			
381	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Initial Ballot	3/1/2013	3/11/2013	Quorum: 76.36% Approval: 54.65%			
382	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Successive Ballot	3/13/2013	3/22/2013	Quorum: 77.48% Approval: 84.27%	No Consensus 3/22/13		NPCC to abstain - international nature of the ERO and BPS is not used in Reliability Standards
383	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.58% Approval: 97.18%	Support 3/14/13		
384	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Initial Ballot	3/13/2013	3/22/2013	Quorum: 88.52% Approval: 98.89%	Support 3/14/13		
385	Project 2007-09	Project 2007-09 - Generator Verification: PRC-024-1	Recirculation Ballot	3/18/2013	3/27/2013	Quorum: 81.33% Approval: 89.44%	Support 1/11/13		

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386	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Successive Ballot	3/27/2013	4/5/2013	Quorum: 78.39% Approval: 57.50%	No Consensus 4/4/13		The RSC did not reach a full consensus however the majority of respondents had indicated they will support the standard - see comment form for further details. Some believe the standard is not necessary and that existing whitepapers alleviate the need for it. In recognition of the NERC BOT's expectations that COM-003 will be approved by the industry and brought before them for approval, NPCC has voted affirmatively and will supply comments for the record outlining our concerns.
387	Project 2007-02	Project 2007-02 Operating Personnel Protocols: COM-003-1	Non-binding Poll	3/27/2013	4/5/2013	Quorum: 77.97% Approval: 54.28%			
388	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.60% Approval: 66.98%	No Consensus 4/23/13		The majority of NPCC's Balancing Authorities have indicated support for the standard, however NPCC as the Regional Entity has concerns based on results of the field trials that were conducted. These field trials have indicated the potential for an increased number of SOL violations as well as potential for increased ACE due to large inadvertent flows with the proposed BAAL limits based on frequency triggers. To be respectful of the positions of the NPCC BAs who will have to implement this new methodology and the support expressed, NPCC as the Regional Entity will cast an Abstention
389	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 42.75%	Oppose 4/23/13		There is a lack of technical justification for the 500 MW threshold within the standard-NPCC will submit suggested improvements

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
390	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Initial Ballot	4/16/2013	4/25/2013	Quorum: 88.51% Approval: 23.84%	Oppose 4/23/13		Losses of large blocks of load are typically caused by coincident transmission contingencies. Excessive and uninformed adjustments made to generation in order to bring the ACE to zero may well lead to further transmission issues. NPCC will submit suggested improvements
391	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
392	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-002-2	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
393	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-013-1	Non-binding Poll	4/16/2013	4/25/2013	Quorum: % Approval: %			
394	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Recirculation Ballot	4/18/2013	4/29/2013	Quorum: 80.70% Approval: 88.15%	No Consensus 3/22/13		
395	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Successive ballot	5/15/2013	5/24/2013	Quorum: 81.25% Approval: 69.23%	Support 5/23/13		The Regional Standard Committee has not expressed any concerns of significance that would warrant a ballot to reject, therefore the RSC recommends a yes vote, "Affirmative", to accept the standard
396	Project 2010-13.2	Project 2010-13.2 Phase 2 of Relay Loadability: Generation	Non-binding Poll	5/15/2013	5/24/2013	Quorum: 80.17% Approval: 61.11%			
397	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Successive Ballot	6/24/2013	7/3/2013	Quorum: 77.65% Approval: 52.71%			
398	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	Non-binding Poll	6/24/2013	7/3/2013	Quorum: 77.12% Approval: 52.48%			
399	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Initial Ballot	7/3/2013	7/12/2013	Quorum: 85.53% Approval: 49.73%			
400	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Successive Ballot	7/10/2013	7/19/2013	Quorum: 76.32% Approval: 58.36%	No Consensus 7/19/13 [Due to the concerns expressed over the potential actions by the NERC BOT and FERC as well as the incremental improvement of the standard over the previous versions, NPCC as the Regional Entity will support the standard and submit comments.]		organizations support the standard as written however some members expressed concern that in order to measure compliance with R1 and R2, the standard will require all Reliability Directives to be investigated to determine if RC approved and documented communication protocols have been violated. Also it was identified that TO, BA communication protocols would have to approved by the RC potentially causing some legal issues if protocols aren't approved and casts question on the enforcement of those protocols. NPCC will be submitting some helpful comments should the standard pass and some non-substantive revision be performed prior to the "final" (previously named recirculation) ballot.
401	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 76.20% Approval: 55.37%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
402	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Successive Ballot	7/10/2013	7/19/2013	Quorum: 85.05% Approval: 72.43%	Support 7/19/13		
403	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	Non-binding Poll	7/10/2013	7/19/2013	Quorum: 82.51% Approval: 64.59%			
404	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves: BAL-001-2	Final Ballot	7/16/2013	7/25/2013	Quorum: 92.31% Approval: 74.54%	No Consensus 7/22/13		The RSC has not reached a full consensus however the majority are in support. Issues outstanding for those not in support are concern over "hitting limits" more frequently and potential issues with BA's potentially "dragging" on the interconnection. NPCC will be voting affirmative on the standard.
405	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Initial Ballot	7/26/2013	8/5/2013	Quorum: 80.05% Approval: 93.00%	Support 8/5/13		
408	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025-1	Final Ballot	8/2/2013	8/12/2013	Quorum: 89.13% Approval: 76.52%	Support 8/12/13		
406	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Initial Ballot	8/2/2013	8/12/2013	Quorum: 76.32% Approval: 62.74%	Support 8/9/13		
407	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	8/2/2013	8/12/2013	Quorum: 75.89% Approval: 55.45%			
409	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Initial Ballot	8/14/2013	8/23/2013	Quorum: 78.33% Approval: 79.42%	Support 8/23/13		
410	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Non-binding Poll	8/14/2013	8/23/2013	Quorum: 77.45% Approval: 81.37%			
411	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Ballot	8/16/2013	8/26/2013	Quorum: 76.14% Approval: 51.10%	No Consensus 8/26/13		NPCC to support with comments
412	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Non-binding Poll	8/16/2013	8/26/2013	Quorum: 75.98% Approval: 53.29%			
413	Project 2010-01	Project 2010-01 - Training - PER-005-2	Ballot	8/23/2013	9/3/2013	Quorum: 75.25% Approval: 34.46%	No Consensus 8/31/13		NPCC to support with comments The most contentious issues raised by RSC members was surrounding the Control Center definition and the potential to vastly expand those needing training subject to the standard and compliance and that there was no need for a standard, rather, the FERC Directives should be addressed through other means.
414	Project 2010-01	Project 2010-01 - Training - PER-005-2	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 80.45% Approval: 34.24%			

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
415	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Ballot	8/23/2013	9/3/2013	Quorum: 81.89% Approval: 43.79%	Oppose 8/31/13		The standard, in the view of the group, has extensive issues including but not limited to, applicability issues, lacks clarity, missing measures, quality, and other substantive issues. NPCC will be submitting detailed comments to address these issues. The RSC does not believe it would be beneficial to support the standard at this point as the next step, if it fails the initial ballot, would still require an additional ballot prior to moving to recirculation due to the substantive changes that are needed for the next revision. NPCC will be submitting helpful comments to NERC and supporting the drafting team effort.
416	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	Non-binding Poll	8/23/2013	9/3/2013	Quorum: 79.95% Approval: 44.23%			
417	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Ballot	8/26/2013	9/4/2013	Quorum: 82.29% Approval: 41.24%	Support 8/31/13		
418	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 79.66% Approval: 40.00%			
419	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Ballot	8/26/2013	9/4/2013	Quorum: 81.96% Approval: 55.76%	Support 8/31/13		
420	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Non-binding Poll	8/26/2013	9/4/2013	Quorum: 80.35% Approval: 58.97%			
421	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	8/26/2013	9/4/2013	Quorum: 78.68% Approval: 66.11%	Support 8/31/13		
426	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023-3	Final Ballot	9/4/2013	9/13/2013	Quorum: 85.93% Approval: 90.83%	Support 8/5/13		
422	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Ballot	9/6/2013	9/16/2013	Quorum: 76.15% Approval: 58.23%	No Consensus 9/12/13		
423	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	Non-binding Poll	9/6/2013	9/16/2013	Quorum: 75.69% Approval: 59.66%			
424	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	Final Ballot	9/11/2013	9/20/2013	Quorum: 91.64% Approval: 98.61%	Support 3/14/13		
425	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	Final Ballot	9/11/2013	9/20/2013	Quorum: 90.98% Approval: 98.92%	Support 3/14/13		
427	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Additional Ballot	10/9/2013	10/21/2013	Quorum: 77.58% Approval: 88.75%	Support 10/16/13		
428	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Non-binding Poll	10/9/2013	10/21/2013	Quorum: 75.89% Approval: 90.04%			
429	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005-3	Final Ballot	10/16/2013	10/25/2013	Quorum: 85.71% Approval: 85.38%			
430	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Additional Ballot	10/18/2013	10/29/2013	Quorum: 75.83% Approval: 72.55%	Support 10/21/13		
431	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation - EOP-010-1	Final Ballot	10/25/2013	11/4/2013	Quorum: 86.90% Approval: 91.95%			
432	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	10/25/2013	11/7/2013	Quorum: 76.67% Approval: 58.24%	No Consensus 11/1/13		
433	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	11/1/2013	11/12/2013	Quorum: 76.23% Approval: 56.48%	Support 11/11/13		

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434	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Initial Ballot	11/4/2013	11/13/2013	Quorum: 76.12% Approval: 67.35%	Support 11/5/13		
435	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-006-4	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 75.58%	Support 11/5/13		
436	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-009-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 68.40%	Support 11/5/13		
437	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.82% Approval: 58.03%	Support 11/5/13		
438	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-011-1	Initial Ballot	11/4/2013	11/13/2013	Quorum: 75.52% Approval: 71.35%	Support 11/5/13		
439	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Initial Ballot	11/4/2013	11/15/2013	Quorum: 76.42% Approval: 77.82%	Support 11/5/13		
440	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	Final Ballot	11/8/2013	11/18/2013	Quorum: 81.68% Approval: 74.34%	Support 10/21/13		
441	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Additional Ballot	11/8/2013	11/20/2013	Quorum: 81.69% Approval: 82.97%	No Consensus 8/26/13		
442	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.05% Approval: 73.46%	Support 8/31/13		
443	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	11/8/2013	11/20/2013	Quorum: 79.84% Approval: 69.42%	Support 8/31/13		
444	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	11/13/2013	11/22/2013	Quorum: 80.54% Approval: 57.59%	Support 8/31/13		
445	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Additional Ballot	11/15/2013	11/25/2013	Quorum: 80.81% Approval: 69.43%			
446	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	11/15/2013	11/25/2013	Quorum: 81.06% Approval: 66.09%			
447	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2	Additional Ballot	12/2/2013	12/12/2013	Quorum: 75.29% Approval: 64.24%	No Consensus 12/9/13	Affirmative	
448	Project 2007-11	Project 2007-11 Disturbance Monitoring - PRC-002-2	Initial Ballot	12/6/2013	12/16/2013	Quorum: 82.25% Approval: 43.29%	No Consensus 12/15/13	Affirmative	Highlights of comments received expressed: • Agreement with the methodology to determine BES locations for which data had to be captured • Use of the term "locations" • DDR for Flowgates, IROLs • Clarification needed for some data that is to be captured • Editorial suggestions
449	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1	Final Ballot	12/6/2013	12/16/2013	Quorum: 87.53% Approval: 77.49%	Support 8/31/13	Affirmative	
450	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-006-4	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 80.77%	Support 11/5/13	Affirmative	
451	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-009-2	Final Ballot	12/10/2013	12/20/2013	Quorum: 85.07% Approval: 72.86%	Support 11/5/13	Affirmative	
452	Project 2008-12	Project 2008-12 Coordinate Interchange Standards - INT-011-1	Final Ballot	12/10/2013	12/20/2013	Quorum: 84.78% Approval: 72.91%	Support 11/5/13	Affirmative	
453	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	Final Ballot	12/11/2013	12/20/2013	Quorum: 87.16% Approval: 86.40%	No Consensus 8/26/13	Affirmative	
454	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4	Final Ballot	12/13/2013	12/23/2013	Quorum: 84.34% Approval: 75.35%		Affirmative	
455	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-027-1	Additional Ballot	12/9/2013	12/31/2013	Quorum: 76.60% Approval: 65.71%	No Consensus 12/27/13	Affirmative	
456	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Additional Ballot	1/10/2014	1/21/2014	Quorum: 76.92% Approval: 81.41%	Support 8/31/13	Affirmative	
457	Project 2010-01	Project 2010-01 - Training - PER-005-2	Additional Ballot	1/8/2014	1/22/2014	Quorum: 7912% Approval: 74.63%	Support 11/11/13	Affirmative	
458	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 81.19%	Support 11/5/13	Affirmative	
459	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Additional Ballot	1/10/2014	1/22/2014	Quorum: 75.22% Approval: 90.23%	Support 11/5/13	Affirmative	

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460	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Additional Ballot	1/16/2014	1/29/2014	Quorum: 76.12% Approval: 92.17%	Support 11/5/13	Affirmative		
461	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Additional Ballot	1/22/2014	1/31/2014	Quorum: 76.03% Approval: 71.86%	No Consensus 11/1/13	Affirmative	Ballot Period Extended to 2/4/14	
462	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-004-3	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.88% Approval: 83.44%	Support 11/5/13	Affirmative		
463	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - INT-010-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 83.58% Approval: 91.51%	Support 11/5/13	Affirmative		
464	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-033-1	Final Ballot	1/27/2014	2/5/2014	Quorum: 82.49% Approval: 82.45%	Support 8/31/13	Affirmative		
465	Project 2010-01	Project 2010-01 - Training - PER-005-2	Final Ballot	1/27/2014	2/5/2014	Quorum: 84.02% Approval: 77.06%	Support 11/11/13	Affirmative		
466	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards - Definition	Final Ballot	1/31/2014	2/10/2014	Quorum: 81.79% Approval: 90.12%	Support 11/5/13	Affirmative		
467	Project 2010-05.1	Project 2010-05.1 –Protection Systems: Phase 1 (Misoperations): PRC-004-3	Additional Ballot	2/21/2014	3/3/2014	Quorum: 75.06% Approval: 62.63%	Support 9/5/12	Affirmative	Ballot Period Extended to 3/11/14	
468	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-002-4	Final Ballot	3/28/2014	4/7/2014	Quorum: 78.21% Approval: 77.62%	Support 3/28/14	Affirmative		
469	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Additional Ballot	4/1/2014	4/10/2014	Quorum: 76.92% Approval: 83.40%	Support 8/31/13	Affirmative		
470	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-002-3	Additional Ballot	4/4/2014	4/14/2014	Quorum: 78.03% Approval: 82.40%		--		
471	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	Initial Ballot	4/20/2014	4/24/2014	Quorum: 88.60% Approval: 82.07%	Support 4/23/14	Abstain		
472	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	Final Ballot	4/25/2014	5/5/2014	Quorum: 80.37% Approval: 90.00%	Support--4/25/14	Affirmative		
473	Project 2013-04	Project 2013-04 - Voltage and Reactive Control - VAR-001-4, VAR-002-3	Final Ballot	4/23/2014	5/5/2014	Quorum: 83.84% Approval: 88.26%	Support--4/10/14	Affirmative		
474	Project 2014-04	Project 2014-04 - Physical Security - CIP-014-1	Final Ballot	5/1/2014	5/5/2014	Quorum: 92.53% Approval: 85.61%	Support--4/23/14	Abstain		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Initial Ballot	5/6/2014	5/15/2014	Quorum: 85.79%/79.08% Approval: 86.28%/78.81%	No Consensus--5/15/14	Reject		
476	Project 2012-13	Project 2012-13 - NUC - Nuclear Plant Interface Coordination	Initial Ballot	5/13/2014	5/22/2014	Quorum: 80.60% Approval: 97.36%	Support--5/20/14	Affirmative		
477	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays) - PRC-005-X	Initial Ballot	5/23/2014	6/2/2014	Quorum: 85.42% Approval: 47.89%	Support	Affirmative		
478	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Initial Ballot	5/30/2014	6/9/2014	Quorum: 79.06% Approval: 17.02%	Does not Support--6/6/14	Negative		
475	Project 2010-02	Project 2010-02 - Connecting Facilities to the Grid - FAC-001-2 and FAC-002-2	Final Ballot	6/12/2014	6/23/2014	Quorum: Approval: 89.03%/83.46%	Support	Affirmative		
479	Project 2007-11	Project 2007-11 - Disturbance Monitoring - PRC-002-2	Additional Ballot	6/13/2014	6/23/2014	Quorum: 77.69% Approval: 52.29%	Support	Affirmative	Extended to achieve a quorum.	Last RSC Meeting
480	Project 2010-05.1	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Additional Ballot	6/20/2014	7/9/2014	Quorum: 76.98% Approval: 74.53%	Support	Affirmative	Extended to achieve a quorum.	
481	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Ballot	6/23/2014	7/2/2014	Quorum: 82.32%/82.59%/82.59%/82.85%/82.85%/82.06%/82.59%/82.85%/82.85%/81.00%/80.74% Approval: 68.57%/36.94%/47.87%/60.26%/61.67%/57.94%/30.99%/62.18%/63.07%/62.64%/64.70%	No Consensus--6/24/14	Affirmative Negative Affirmative Affirmative Affirmative Affirmative Negative Affirmative Affirmative		
482	Project 2012-13	Project 2012-13 NUC - Nuclear Plant Interface Coordination	Final Ballot	6/24/2014	7/3/2014	Quorum: 88.63% Approval: 97.23%	Support--6/23/14	Affirmative		
483	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions Rich HTML Content 1	Final Ballot	7/7/2014	7/16/2014	Quorum: 80.73%/80.49%/80.00%/80.24%/80.24%/80.49%/80.24%/78.29%	CIP-003 No CIP-004 Yes CIP-006 Yes CIP-007 Yes CIP-009 Yes			

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483	Project 2014-02	Rich Hume Content 1 http://www.nerc.com/pa/Stand/Pages/Project-2014-XX-Critical-Infrastructure-Protection-Version-5-Revisions.aspx	Final Ballot	7/7/2014	7/16/2014	Approval: 35.67%/80.76%/76.24%/78.41%/85.32%/49.42%/82.55%/78.58%	CIP-003-5 Yes CIP-010 Yes CIP-011 Yes Definitions Yes Support--7/14/14		
484	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Final Ballot	7/16/2014	7/25/2014	Quorum: 78.92% Approval: 58.88%	Support--7/23/14		
485	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	7/18/2014	7/28/2014	Quorum: 79.49%/80.15%/80.00%/80.83%/80.36% Approval: 91.38%/92.20%/89.51%/90.58%/87.09%	Support--7/24/14	Affirmative	
486	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	7/21/2014	7/30/2014	Quorum: 82.67% Approval: 55.77%		Affirmative	
487	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Initial Ballot	7/29/2014	8/7/2014	Quorum: 76.37% Approval: 76.91%		Affirmative	
488	Project 2012-13	Project 2009-03 Emergency Operations	Initial Ballot	8/6/2014	8/15/2014	Quorum: 77.66% Approval: 42.27%	Negative--8/14/14	Negative	
489	Project 2014-01	Project 2010-05.1 - Protection System: Phase 1 (Misoperations) - PRC-004	Final Ballot	7/29/2014	8/7/2014	Quorum: 77.94% Approval: 79.75%	Support	Affirmative	
490	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	8/27/2014	9/5/2014	Quorum: 85.32%/86.01% Approval: 95.35%/95.86%	Support	Affirmative	
491	Project 2007-17.3	Project 2007-17.3 - Protection System Maintenance and	Additional Ballot	9/3/2014	9/12/2014	Quorum: 84.33% Approval: 76.03%	Support--9/4/14	Affirmative	
492	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	Additional Ballot	9/10/2014	9/19/2014	Quorum: 85.75%/84.96%/84.96%/85.22%/84.96%/85.22%/85.49%/85.22%/86.28%/83.11%/83.91% Approval: 76.12%/74.23%/75.67%/85.49%/75.96%/78.67%/48.73%/78.87%/87.03%/93.34%/90.13%	TOP-001-3: Negative TOP-002-4: Affirmative TOP-003-3: Affirmative IRO-001-4: No consensus however the majority indicated an Affirmative vote IRO-002-4: Negative IRO-008-2: No consensus, a majority indicated a Negative and the others indicated abstention IRO-010-2: Affirmative IRO-014-3: Negative IRO-017-1: Affirmative Implementation Plan and Definitions: Affirmative 9/18/14		
493	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	9/23/2014	10/2/2014	Quorum: 79.94% Approval: 46.73%	Negative--10/1/14		
494	Project 2010-13.3	Project 2010-13.3 - Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	9/26/2014	10/6/2014	Quorum: 79.01% Approval: 53.02%	Affirmative--10/1/14		
495	Project 2012-13	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Additional Ballot	9/29/2014	10/8/2014	Quorum: 83.24%/84.82% Approval: 80.69%/84.05%	Affirmative--10/7/14	Affirmative	
496	Project 2012-13	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	10/1/2014	10/10/2014	Quorum: 82.93% Approval: 57.95%	Affirmative--10/7/14		
497	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems (Phase 2 of Protection Systems)	Additional Ballot	10/3/2014	10/14/2014	Quorum: 80.54% Approval: 75.79% Approval:	Affirmative--10/7/14		
498	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/7/2014	10/16/2014	Quorum: 81.91%/82.12% Approval: 94.92%/94.37%	Affirmative--10/14/14		

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499	Project 2014-02	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	10/8/2014	10/17/2014	Quorum: 84.63%/84.15%/84.15%/83.90%/83.41%/83.66%/83.96%/84.49%/83.96%/83.96%/84.22 Approval: 93.21%/68.09%/74.25%/79.91%/85.68%/89.01%/91.79%/81.34%/96.63%/96.63%/95.52%/85.93%/98.13%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative	CIP-003-6 and CIP-010-2 Affirmative	
500	Project 2009-03	Project 2009-03 Emergency Operations	Additional Ballot	10/10/2014	10/20/2014	Quorum: 80.93% Approval: 70.41%	Affirmative--10/17/14		
501	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (IRO-001-4, IRO-002-4, IRO-010-2, two Definitions, and Implementation Plan)	Final Ballot	10/10/2014	10/20/2014	Quorum: 90/77%/89.97%/89.97%/88.39%/88.39% Approval: 82.64%/85.96%/86.22%/94.07%/91.84%	Affirmative--10/17/14		
502	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards (TOP-002-4, TOP-003-3, IRO-008-2, IRO-014-3, and IRO-017-1)	Final Ballot	10/10/2014	10/20/2014	Quorum: 89.71%/88.39%/89.71%/89.71%/89.97% 84.76%/86.55%/83.73%/89.88%/82.58%	Affirmative--10/17/14		
503	Project 2007-11	Project 2007-11 Disturbance Monitoring	Additional Ballot	10/10/2014	10/21/2014	Quorum: 77..69% Approval: 71.38%	Affirmative--10/17/14		
504	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Additional Ballot	10/10/2014	10/22/2014	Quorum: 85.13%/83.29% Approval: 94.75%/93.98%	Affirmative--10/20/14		
505	Project 2014-03	Project 2007-17.3 (PRC-005-X) Protection System Maintenance and Testing - Phase 3 (Sudden Pressure Relays)	Final Ballot	10/20/2014	10/29/2014	Quorum: 88.25% Approval: 74.14%	Affirmative--10/28/14		
506	Project 2014-03	Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS)	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.53% Approval: 83.12%	Affirmative--10/31/14		
507	Project 2007-11	Project 2007-11 Disturbance Monitoring	Final Ballot	10/28/2014	11/6/2014	Quorum: 81.89% Approval: 68.51%	Affirmative--10/31/14		
508	Project 2007-11	Project 2010-05.2 Phase 2 of Special Protection Systems	Final Ballot	10/28/2014	11/6/2014	Quorum: 85.41% Approval: 73.33%	Negative--10/14/14		
509	Project 2007-11	Project 2009-03 Emergency Operations	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.19% Approval: 73.20%	Affirmative--10/17/14		
510	Project 2007-11	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Final Ballot	10/28/2014	11/6/2014	Quorum: 89.49%/87.66%/87.08% Approval: 92.91%/92.15%/95.62%	Affirmative--10/20/14		
511	Project 2014-03	Project 2014-02 Critical Infrastructure Protection Standards Version 5 Revisions	Final Ballot	10/28/2014	11/6/2014	Quorum: 87.56%/87.32%87.07%/87.56%/87.80%87.56%86.59% Approval: 83.84%/95.34%/86.00%/95.35%91.17%/83.88%/95.40%/92.76%	CIP-003-6 no consensus CIP-010-2 no consensus New Definitions-Affirmative Updated Definitions-Affirmative Implementation Plan-Affirmative Version X Materials-Affirmative Non-binding polls-Affirmative		
512	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	11/4/2014	11/10/2014	Quorum: 78.36% Approval: 60.21%	Affirmative--11/4/14		
513	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Additional Ballot	11/12/2014	11/21/2014	Quorum: 79.73% Approval: 77.29%	Affirmative--11/21/14		
514	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Additional Ballot	11/14/2014	11/24/2014	Quorum: 79.83% Approval: 67.39%	Affirmative--10/1/14		
515	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.27% Approval: 78.05%	Affirmative--12/12/14		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments
516	Project 2014-03	Project 2010-13.3 Phase 3 of Relay Loadability: Stable Power Swings	Final Ballot	12/5/2014	12/16/2014	Quorum: 84.81% Approval: 68.08%	Affirmative--12/15/14		
517	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	Initial Ballots	12/10/2014	12/23/2014	Quorum: 79.38%/79.72%/79.60 % Approval: 92.69%/93.55%/93.67 %	Affirmative--12/22/14		
518	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards	Additional Ballot	12/19/2014	1/7/2015	Quorum: 80.47% Approval: 72.43%	Affirmative--1/6/15		
519	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions	Additional Ballot	12/30/2014	1/9/2015	Quorum: 81.22%/81.71%/81.46 %/81.71%/81.71%/81. 22%/81.71%/81.46% Approval: 81.92%/98.89%/98.86 %/88.13%/98.89%/86. 02%/89.63%/97.21%	CIP-003-7 Binding and non-binding polls-no consensus CIP-003-7 Definition-Affirmative CIP-010-7 Binding and non-binding polls- Affirmative CIP-010-7 Definition- Affirmative CIP-004-7 Binding and non-binding polls – Affirmative CIP-007-7 Binding and non-binding polls –Affirmative CIP-011-7 Binding and non-binding polls –Affirmative CIP Implementation Plan- Affirmative 1/8/2015		
520	Project 2014-03	2014-03 - Revisions to TOP and IRO Standards - TOP-001-3	Final Ballots	1/15/2015	1/21/2015	Quorum: 84.70% Approval: 72.69%	Affirmative--1/6/15		
521	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Initial Ballots	1/12/2015	1/22/2015	Quorum: 77.93% Approval: 93.74%	Affirmative--1/22/15		
522	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-001-1.1(ii), PRC-019-2, and PRC-024-2	Final Ballots	1/13/2015	1/22/2015	Quorum: 89.27%/89.30%/89.52 % Approval: 93.99%/94.03%/95.82 %	Affirmative--1/22/15		
523	Project 2014-02	2014-02 - Critical Infrastructure Protection Standards Version 5 Revisions CIP-003-7, CIP-004-7, CIP-010-3, and CIP-011-3	Final Ballot	1/23/2015	2/2/2015	Quorum: 84.15%/84.39%/84.15 %/84.39%/84.39%/83. 90%/84.39%/83.66% Approval: 79.76%/98.94%/98.94 %/86.76%/98.93%/84. 07%/90.10%/97.32%	Affirmative--1/29/15		
524	Project 2014-01	2014-01 - Standards Applicability for Dispersed Generation Resources - PRC-005-5	Final Ballot	3/2/2015	3/11/2015	Quorum: 83.52% Approval: 98.03%	Affirmative--1/22/15		
525	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	3/6/2015	3/16/2015	Quorum: 77.29% Approval: 59.30%	Negative--3/13/2015		
526	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Initial Ballot	3/27/2015	4/7/2015	Quorum: 79.93% Approval: 84.31%	Affirmative--3/31/15		
527	Project 2014-04	Project 2014-04 Physical Security	Initial Ballot	3/31/2015	4/9/2015	Quorum: 88.33% Approval: 89.95%	Affirmative--3/31/15		
528	Project 2008-02.2	Project 2008-02.2 Phase 2 of Undervoltage Load Shedding (UVLS): Misoperations	Final Ballot	4/17/2015	4/27/2015	Quorum: 84.86% Approval: 89.63%	Affirmative--3/31/15		
529	Project 2014-04	Project 2014-04 Physical Security	Final Ballot	4/20/2015	4/29/2015	Quorum: 92.00% Approval: 92.35%	Affirmative--3/31/15		
530	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	5/6/2015	5/15/2015	Quorum: 81.79% Approval: 39.63%	Negative--5//13/15		
531	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Initial Ballot	6/29/2015	7/8/2015	Quorum: 75.23%/84.00% Approval: 90.35%/97.50%	Affirmative--7/7/15		

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532	Project 2015-04	2015-04 Alignment of Terms	Initial Ballot	7/17/2015	7/27/2015	Quorum: 90.43%/91.17%/91.10%/91.01%/91.10%/91.17%/91.17%/91.34%/90.97%/91.40%/90.10%/91.01%/91.07%/91.07%/91.07%/91.34%/91.43%/90.75%/91.34%/91.01%/91.40%/91.01%/91.01%/91.01%/91.01%/91.01% Approval: 91.46%/88.57%/86.68%/97.06%/97.10%/81.06%/80.73%/96.38%/97.03%/69.80%/95.38%/93.62%/96.83%/97.00%/98.55%/87.37%/89.99%/84.38%/88.06%/90.37%/97.75%/91.28%/87.71%/89.44%/87.15%/98.24%	Affirmative--7/24/15		
533	Project 2015-06	2015-06 Interconnection Reliability Operations and Coordination	Final Ballots	7/22/2015	7/31/2015	Quorum: 85.98%/90.67%% Approval: 88.23%/96.84%	Affirmative--7/7/15		
534	Project 2010-14.1	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Additional Ballot	8/11/2015	8/20/2015	Quorum: 75.92% Approval: 69.26%	Affirmative--8/17/15		
535	Project 2007-06	Project 2007-06 System Protection Coordination	Additional Ballot	9/2/2015	9/11/2015	Quorum: 84.34% Approval: 69.76%	Affirmative--9/8/15		
536	Project 2007-06	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	9/2/2015	9/11/2015	Quorum: 87.16% Approval: 62.55%	Affirmative--9/11/15		
537	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Initial Ballot	9/4/2015	9/14/2015	Quorum: 83.81% Approval: 55.97%	Abstention--9/14/15		
538	Project 2015-04	2015-04 Alignment of Terms	Final Ballot	9/4/2015	9/14/2015	Quorum: 96.81%/97.53%/97.51%/97.48%/97.51%/97.53%/97.53%/97.11%/97.11%/97.85%/96.80%/97.12%/97.14%/97.14%/97.14%/97.11%/97.14%/96.80%/97.11%/97.48%/97.85%/97.48%/97.48%/97.48%/97.48%/97.48% Approval: 93.13%/92.89%/91.33%/98.07%/98.07%/84.78%/84.75%/98.30%/98.06%/75.63%/95.46%/94.48%/98.31%/97.11%/98.57%/90.80%/95.60%/90.46%/92.07%/92.49%/97.81%/92.84%/91.09%/91.32%/90.80%/98.29%	Affirmative--7/24/15		
539	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Initial Ballot	9/4/2015	9/16/2015	Quorum: 86.97% Approval: 96.73%	Affirmative--9/16/15		
540	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Initial Ballot	9/9/2015	9/18/2015	Quorum: 85.57%	Affirmative--9/18/15		

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						Approval: 87.36%			
541	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Initial Ballot	9/25/2015	10/5/2015	Quorum: 83.70% Approval: 48.10%	N egative--10/2/15		
542	Project 2010-05.3	Project 2010-14.1 Phase 1 of Balancing Authority Reliability-based Controls: Reserves	Final Ballot	9/29/2015	10/8/2015	Quorum: 84.28% Approval: 74.61%	Affirmative--8/17/15		
543	Project 2010-05.3	Project 2007-06 System Protection Coordination	Final Ballot	10/5/2015	10/14/2015	Quorum: 89.16% Approval: 80.94%	Affirmative--9/8/15		
544	Project 2010-05.3	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	Final Ballot	10/6/2015	10/15/2015	Quorum: 89.60% Approval: 90.01%	Affirmative--9/18/15		
545	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	Final Ballot	10/15/2015	10/26/2015	Quorum: 90.00% Approval: 96.38%	Affirmative--9/16/15		
546	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Initial Ballot	10/30/2015	11/9/2015	Quorum: 84.59%/84.49% Approval: 47.38%/48.00%	Abstention--11/5/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Initial Ballot	11/3/2015	11/12/2015	Quorum: 84.40% Approval: 98.17%	Affirmative--11/5/15		
548	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Initial Ballot	11/6/2015	11/16/2015	Quorum: 88.18% Approval: 53.60%	Affirmative--11/13/15		
549	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Additional Ballot	11/10/2015	11/19/2015	Quorum: 83.18% Approval: 57.29%	Affirmative--11/18/15		
550	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Initial Ballot	12/7/2015	12/16/2015	Quorum: 85.38% Approval: 82.56%	Negative--12/8/15		
547	Project 2010-05.3	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls - BAL-004-2	Final Ballot	12/8/2015	12/17/2015	Quorum: 88.65% Approval: 98.26%	Affirmative--11/5/15		
551	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	12/30/2015	1/8/2016	Quorum: 83.39%/80.88% Approval: 60.39%/92.94%	Affirmative--12/3015		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Additional Ballot	12/31/2015	1/11/2016	Quorum: 84.13%/83.17%/84.44% Approval: 70.64%/75.54%/94.30%	BAL-005-1--Negative--1/10/16 BAL-006--Affirmative--1/10/16 FAC-003-1--Abstention--1/10/16		
553	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Additional Ballot	1/15/2016	1/25/2016	Quorum: 82.88%/82.18% Approval: 72.13%/68.01%	Affirmative--1/25/16		
554	Project 2010-07.1	Project 2010-07.1 Vegetation Management	Final Ballot	1/29/2016	2/8/2016	Quorum:90.03% Approval: 96.18%	Affirmative--2/1/16		
552	Project 2010-14.2.1	Project 2010-14.2.1 Phase 2 of Balancing Authority Reliability-based Controls – BAL-005 and BAL-006	Final Ballot	1/29/2016	2/8/2016	Quorum: 86.35%/86.98%/86.67% Approval: 72.06%/94.61%/80.15%	Affirmative--2/3/15		
551	Project 2010-05.3	Project 2009-02 Real-time Reliability Monitoring and Analysis Capabilities	Final Ballot	2/17/2016	2/26/2016	Quorum: 88.36%/87.79% Approval: 75.68%/73.87%	Affirmative--1/25/16		
552	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Additional Ballot	3/9/2016	3/18/2016	Quorum: 75.55% Approval: 78.87%	Affirmative--3/10/16		
553	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Initial Ballot	4/15/2016	4/25/2016	Quorum: 83.39%/83.33% Approval: 80.57%/78..39%	Affirmative--4/20/16		
554	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems: Remedial Action Schemes (RAS)	Final Ballot	4/20/2016	4/29/2016	Quorum: 81.19%/87.15%	Affirmative--3/10/16		

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						Approval: 80.36%/93.43%	~~Affirmative--5/16/16~~		
555	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Additional Ballot	4/27/2016	5/6/2016	Quorum: 81.03% Approval: 82.64%	Affirmative--5/6/16		
556	Project 2007-06.2	Project 2007-06.2 Phase 2 of System Protection Coordination	Final Ballot	5/17/2016	5/26/2016	Quorum: 88.96%/88.36% Approval: 82.52%/83.37%	Affirmative--4/20/16		
557	Project 2015-07	Project 2015-07 Internal Communications Capabilities	Final Ballot	6/15/2016	6/24/2016	Quorum: 84.52% Approval: 83.25%	Affirmative--5/6/16		
558	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Initial Ballot	7/25/2016	8/3/2016	Quorum: 84.50%/85.51% Approval: 67.25%/64.59%	Affirmative--8/1/16		
559	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 EOP-006-3 EOP-008-2	Initial Ballot	8/4/2016	8/15/2016	Quorum: 80.45%/81.14%/80.79% Approval: 52.90%/66.87%/84.13%	Negative--8/4/16		
560	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Initial Ballot	8/26/2016	9/6/2016	Quorum: 85.00%/84.37%/84.62% Approval: 41.54%/41.77%/30.63%	Negative--9/6/16		
561	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Initial Ballot	8/30/2016	9/8/2016	Quorum: 82.75% Approval: 80.32%	Affirmative--9/8/16		
562	Project 2015-INT-01	Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Initial Ballot	9/2/2016	9/12/2016	Quorum: 75.43% Approval: 91.68%	Affirmative--9/12/16		
563	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Additional Ballot	10/5/2016	10/14/2016	Quorum: 83.33%/81.79% Approval: 70.77%/68.85%	Affirmative--10/13/16		
564	Project 2015-INT-01	Project 2015-INT-01 Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	Final Ballot	10/13/2016	10/24/2016	Quorum: 81.25% Approval: 91.31%	Affirmative--9/12/16		
565	Project 2016-02	Project 2016-02 Modifications to CIP Standards	Additional Ballot	11/23/2016	12/5/2016	Quorum: 76.40%/76.63% Approval: 85.56%/75.54%	Affirmative--12/1/16		
566	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3 and EOP-006-3	Additional Ballot	11/30/2016	12/9/2016	Quorum: 80.71%/82.43% Approval: 76.93%/77.17%	Affirmative--11/30/16		
567	Project 2015-08	Project 2015-08 Emergency Operations EOP-008-2	Final Ballot	11/30/2016	12/9/2016	Quorum: 93.36% Approval: 93.17%	Affirmative--11/30/16		
568	Project 2016-01	Project 2016-01 Modifications to TOP and IRO Standards	Final Ballot	12/2/2016	12/12/2016	Quorum: 90.74%/90.40% Approval: 74.30%/72.52%	Affirmative--12/2/16		
569	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7 and Implementation	Final Ballot	12/9/2016	12/19/2016	Quorum: 82.89%/83.14% Approval: 87.95%/83.03%	Affirmative--12/1/16		
570	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Additional Ballot	12/28/2016	1/6/2017	Quorum: 79.47% Approval: 93.55%	Affirmative--1/4/17		
571	Project 2015-08	Project 2015-08 Emergency Operations EOP-005-3, EOP-006-3	Final Ballot	12/28/2016	1/6/2017	Quorum: 91.00%/91.55% Approval: 83.65%/80.56%	Affirmative--1/4/17		
572	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Initial Ballot	1/16/2017	1/25/2017	Quorum: 77.81%/76.71%/77.26%/76.71%	~~Affirmative--1/23/17~~		

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						Approval: 81.30%/87.87%/86.75%/86.47%	Affirmative--1/23/17		
573	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Initial Ballot	2/24/2017	3/6/2017	Quorum: 87.13% Approval: 10.36%	Abstain--3/2/17		
574	Project 2015-08	Project 2015-08 Emergency Operations EOP-004-4	Final Ballot	1/24/2017	2/2/2017	Quorum: 84.46% Approval: 93.80%	Affirmative--1/4/17		
575	Project 2016-02	Project 2016-02 Modifications to CIP Standards | CIP-003-7(i) Implementation Plan and 2 Definitions	Final Ballot	1/30/2017	2/8/2017	Quorum: 86.58%/85.48%/86.03%/85.48% Approval: 78.55%/86.00%/85.81%/85.54%	Affirmative--1/23/17		
576	SPM	Revisions to the NERC Standards Process Manual	Initial Ballot	4/24/2017	5/3/2017	Quorum: 78.21% Approval: 64.72%			
577	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Additional Ballot	6/6/2017	6/15/2017	Quorum: 76.02%/76.02%/77.21% Approval: 89.84%/82.92%/88.64%	Affirmative--6/8/17		
578	Project 2016-03	Project 2016-03 Cyber Security Supply Chain Risk Management	Final Ballot	7/11/2017	7/20/2017	Quorum: 81.59%/81.33%/82.84% Approval: 88.79%/81.40%/84.19%	Affirmative--6/8/17		
579	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Initial Ballot	8/2/2017	8/11/2017	Quorum: 79.87% Approval: 72.67%	Affirmative--8/3/17		
580	Project 2016-04	Project 2016-04 Modifications to PRC-025-1	Initial Ballot	8/29/2017	9/8/2017	Quorum: 80.45% Approval: 78.79%	Affirmative--9/1/17		
581	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-012-1 Control Center Communication Networks	Initial Ballot	8/14/2017	9/12/2017	Quorum: 80.00% Approval: 42.74%	Affirmative--9/1/17		
582	Project 2015-10	Project 2015-10 Single Points of Failure TPL-001	Initial Ballot	9/8/2017	10/23/2017	Quorum: 82.71% Approval: 30.50%	Abstain--10/18/17		
583	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-2	Final Ballot	10/20/2017	10/30/2017	Quorum: 88.74% Approval: 73.35%	Affirmative--8/3/17		
584	Project 2016-02	Project 2016-02 Modifications to CIP Standards CIP-002-6	Initial Ballot	9/14/2017	10/30/2017	Quorum: 85.40% Approval: 66.78%	Affirmative--10/30/17		
585	Project 2015-09	Project 2015-09 Establish and Communicate System Operating Limits	Initial Ballot	11/3/2017	11/13/2017	Quorum: 87.01%/86.90%/86.90%/85.57%/85.85 Approval: 58.12%/63.17%/56.55%/76.40%/68.59%	Affirmative--11/10/17		

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments

Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments

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Line	Project	Link to Ballot Results https://standards.nerc.net/Ballot.aspx (clicking in the column to the right of "Ballot Periods" column links to the Ballot Results)	Ballot Type	Start Date	End Date (Sorted Oldest to Newest)	Ballot Results	Recommendation / Date	How NPCC Voted	Comments

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1.	N/A	Standards Project Prioritization Reference Document and Tool	Project Prioritization Tool		1/21/11	2/10/11	Yes 2/10/11
2.	Project 2007-23	Project 2007-23 - Violation Severity Levels	VSLs		1/20/11	2/18/11	Yes 2/18/11
3.	N/A	CAN-0015--Draft CAN-0015 Unavailability of NERC Tools	CAN-0015 Unavailability of NERC Tools		2/4/11	2/18/11	Yes 2/18/11
4	N/A	CAN-0016--Draft CAN-0016 CIP-001-1 R1 - Applicability to Non-BES	CAN-0016 CIP-001-1, R1		2/4/11	2/18/11	Yes 2/18/11
5.	N/A	CAN-0018--Draft CAN-0018 FAC-008 R.1.2.1 - Terminal Equipment	CAN-0018 FAC-008, R.1.2.1		2/4/11	2/18/11	Yes 2/18/11
6.	Regional Standard	Regional Reliability Standards - PRC-006-NPCC-1 - Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		1/10/11	2/24/11	
7.	Project 2007-07	Project 2007-07 - Vegetation Management - FAC-003	FAC-003-2		1/27/11	2/28/11	Yes 2/28/11
8.	N/A	CAN-0017--Draft CAN-0017 CIP-007 R5 System Access and Password Controls	CAN-0017 CIP-007, R5		2/11/11	3/4/11	Yes 3/4/11
9.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1		2/4/11	3/7/11	Yes 3/7/11
10.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002, IRO-001, and IRO-014	COM-001 COM-002 IRO-001 IRO-014		1/18/11	3/7/11	Yes 3/7/11
11.	NERC RoP	Proposed Changes to Rules of Procedure to Add Section 1700 - Challenges to Determinations	RoP Section 1700		2/14/11	3/7/11	Yes 3/7/11
12.	Project 2009-02	Project 2009-02 - Real-time Reliability Monitoring and Analysis Capabilities	Concept White Paper		2/16/11	4/4/11	Yes 4/4/11
13.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		3/4/11	4/4/11	Yes 4/4/11

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14.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		3/9/11	4/8/11	Yes 4/8/11
15.	RFC RoP	Notice of Proposed Changes to RFC Rules of Procedure and Request for Comments			3/1/11	4/15/11	
16.	NERC RoP	Proposed Amendments to NERC Rules of Procedure Appendices 3B and 3D	Appendices 3B and 3D		3/1/11	4/15/11	Yes 4/15/11
17.	Project 2010-15	Project 2010-15 - Urgent Action Revisions to CIP-005-3 - CIP-005	CIP-005		3/29/11	4/28/11	Yes 4/27/11
18.	Project 2009-06	Project 2009-06 - Facility Ratings - FAC-008 and FAC-009	FAC-008-3		3/17/11	5/2/11	Yes 5/2/11
19.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		4/13/11	5/12/11	Yes 5/9/11
20.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		4/28/11	5/27/11	Yes 5/27/11
21.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs	TPL-001-2		4/18/11	5/31/11	Yes 5/31/11
22.	Project 2007-03	Project 2007-03 - Real-time Operations - TOP-001 through TOP-008 and PER-001	TOP-001 through TOP-008 and PER-001		4/26/11	6/9/11	Yes 6/9/11
23.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition		5/11/11	6/10/11	Yes 6/10/11
24.	NERC RoP	Rules of Procedure Development Team: BES Definition Exception Process	BES Definition Exception Process		5/11/11	6/10/11	Yes 6/10/11
25.	N/A	CAN-0024--Draft CAN-0024 CIP-002 through CIP-009 Routable Protocols and Data Diodes	CAN-0024 CIP-002 through CIP-009		5/20/11	6/10/11	
26.	N/A	CAN-0029--Draft CAN-0029 PRC-004-1 R1, R2 and R3 Misoperations	CAN-0029 PRC-004-1 R1, R2 and R3		5/20/11	6/10/11	
27.	N/A	CAN-0030--Draft CAN-0030 Attestations	CAN-0030 Attestations		5/20/11	6/10/11	
28.	N/A	CAN-0039--Draft CAN-0039 DOE Form 407	CAN-0039 DOE Form 407		5/20/11	6/10/11	

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29.	Project 2010-05.1	Project 2010-05.1 – Protection Systems: Phase 1 (Misoperations)			6/10/11	7/11/11	
30.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-025-2, MOD-027-1, PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		6/15/11	7/15/11	Yes 7/15/11
31.	Project 2010-07	Project 2010-07 – Generator Requirements at the Transmission Interface – Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR standards		6/17/11	7/17/11	Yes 7/15/11
32.	Project 2007-09	Project 2007-09 – Generator Verification – MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		6/15/11	8/1/11	Yes 8/1/11
33.	NERC RoP	Proposed Changes to NERC Rules of Procedure and associated Appendices (Appendix 4B – Sanction Guidelines; and Appendix 4C – Compliance Monitoring and Enforcement Program)	Appendices 4B and 4C		6/30/11	8/15/11	
34.	N/A	Compliance Application Notice (CAN) Process	CAN Process		8/15/11	9/6/11	Yes 9/6/11
35..	N/A	CAN-0016 CIP-001 R1 - Sabotage Reporting Procedure	CAN-0016 CIP-001, R1		8/15/11	9/6/11	Yes 9/6/11
36.	N/A	DRAFT CANs Posted for Comment and Retirement of CAN-0001 through 0004	CAN-0001 through 0004 Retirement		8/31/11	9/21/11	
37.	NERC RSDP	NERC 2012-2014 Reliability Standards Development Plan	2012-2014 RSDP		9/12/11	9/26/11	Yes 9/26/11
38.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		8/15/11	9/28/11	Yes 9/28/11
39.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System - Initial Ballot of Definition of BES	BES Definition		8/26/11	10/10/11	Yes 10/10/11

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
40.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Technical Principles for Demonstrating BES Exceptions	Technical Principles for Demonstrating BES Exceptions		8/26/11	10/10/11	Yes 10/10/11
41.	N/A	New CAN Template, five DRAFT CANs for Industry review and CANs Status posted to NERC Compliance's Web site.	CANs		9/23/11	10/14/11	Yes 10/14/11
42.	RoP	Proposed Changes to NERC Rules of Procedure and All Appendices			9/2/11	10/17/11	
43.	Project 2010-17	Project 2010-17 - Bulk Electric System (BES) Definition - Rules of procedure Modifications to Support BES Exception Requests	RoP Section 509, Section 1703 and Appendix 5C		9/13/11	10/27/11	Yes 10/27/11
44.	N/A	CAN-0010--Definition of "Annual" and Implementation of Annual Requirements	CAN-0010 Definition of Annual		10/10/11	10/31/11	Yes 10/31/11
45.	N/A	CAN-0011--PRC-005-1 R2: New Equipment	CAN-0011 PRC-005-1 R2		10/10/11	10/31/11	Yes 10/31/11
46.	N/A	CAN-0012--Completion of Periodic Activity Requirements During Implementation Plan	CAN-0012 Completion of Periodic Activity Requirements		10/10/11	10/31/11	Yes 10/31/11
47	N/A	CAN-0013--PRC-023 R1 and R2 Effective Dates for Switch-on-to-Fault Schemes	CAN-0013 PRC-023 R1 and R2		10/10/11	10/31/11	
48.	N/A	CAN-0015--Unavailability of NERC Software Tools	CAN-0015 NERC Tools		10/10/11	10/31/11	Yes 10/31/11
49.	N/A	CAN-0022--VAR-002-1.1b R1 and R3 Generator Operation in Manual Mode	CAN-0022 VAR-002-1.1b R1 and R3		10/10/11	10/31/11	
50.	N/A	CAN-0024--CIP-002 R3 Routable Protocols and Data Diode Devices	CAN-0024 CIP-002, R3		10/10/11	10/31/11	Yes 10/31/11
51.	N/A	CAN-0026--TOP-006 R3 Protection Relays	CAN-0026 TOP-006, R3		10/10/11	10/31/11	Yes 10/31/11
52.	N/A	CAN-0028--TOP-006-1 R1.2 Reporting Responsibilities	CAN-0028 TOP-006-1, R1.2		10/10/11	10/31/11	

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53.	N/A	CAN-0020--TPL-002, TPL-003, TPL-004 and TOP-002 Equipment Maintenance Outages	CAN-0020 TPL-002, TPL-003, TPL-004 and TOP-002		10/19/11	11/9/11	
54.	N/A	CAN-0030--Attestations	CAN-0030		10/19/11	11/9/11	
55.	Project 2011-INT-01	Project 2011-INT-01 - Interpretation of MOD-028 for Florida Power & Light Company	MOD-028, R3.1		10/3/11	11/16/11	Yes 11/16/11
56.	Project 2009-22	Project 2009-22 - Interpretation of COM-002-2 R2 by the IRC	Interpretation of COM-002-2, R2		10/4/11	11/18/11	Yes 11/18/11
57.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface	Various BAL, CIP, EOP, FAC, IRO, MOD, PER, PRC, TOP, and VAR Standards		10/5/11	11/18/11	Yes 11/18/11
58.	N/A	Draft Directive Regarding Generator Transmission Leads	Draft Directive #2011 CAG-001		10/17/11	11/18/11	Yes 11/18/11
59.	Project 2008-10	Project 2008-10 - Interpretation of CIP-006-1 R1.1 by Progress Energy	Interpretation of CIP-006-1, R1.1		10/12/11	11/21/11	Yes 11/21/11
60.	N/A	CAN-0040 - BAL-003 Frequency Bias Calculation			11/2/11	11/23/11	
61.	N/A	CAN-0043 - PRC-005 Protection System Maintenance and Testing Evidence	PRC-005 Evidence		11/2/11	11/23/11	Yes 11/22/11
62.	Project 2007-12	Project 2007-12 - Frequency Response	BAL-003-1			12/8/11	Yes 12/8/11
63.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2			12/12/11	Yes 12/12/11
64.	N/A	Draft CAN-0027: TOP-003 R2 Coordination of Scheduled Outages	CAN-0027 TOP-003, R2		11/22/11	12/14/11	
65.	NERC RoP	Proposed Changes to the NERC Rules of Procedure and Associated Appendices			11/7/11	12/22/11	

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
66.	NERC RoP	Notice of Revisions to Proposed New Sections 1.1.24 and 5.11 of Appendix 4C of the NERC Rules of Procedure, as Originally Posted for Comment on November 7, 2011			11/22/11	12/22/11	
67.	Regional Standard	Regional Reliability Standard PRC-006-NPCC-1 — Automatic Underfrequency Load Shedding	PRC-006-NPCC-1		11/22/11	12/22/11	
68.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1 (Version 5 CIP Standards)	Version 5 CIP Standards		11/7/11	1/6/12	Yes 1/6/12
69.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations - TOP-001-2, TOP-002-3 and TOP-003-2	TOP-001-2 TOP-002-3 TOP-003-2		12/14/11	1/12/12	Yes 1/12/12
70.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition, Phase 2		1/4/12	2/3/12	Yes 2/3/12
71.	N/A	Order 754 - Request for Data or Information	Data Request		12/22/11	2/6/12	Yes 2/6/12
72.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001 COM-002 IRO-001-3		1/9/12	2/9/12	Yes 2/8/12
73.	WECC Regional Standard	Regional Reliability Standard BAL-004-WECC-02 - Automatic Time Error Correction	BAL-004-WECC-02		1/23/12	3/9/12	
74.	WECC Regional Standard	Regional Reliability Standard BAL-001-0.1a - Real Power Balancing Control Performance - WECC Variance	BAL-001-0.1a		1/23/12	3/9/12	
75.	N/A	NERC Functional Model Demand Response Functions and Entities	NERC Functional Model		2/13/12	3/14/12	
76.	Project 2009-26	Project 2009-26 - Interpretation of CIP-004-1 for WECC	Interpretation of CIP-004-1		2/8/12	3/23/12	Yes 3/23/12

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
77.	Project 2010-INT-05	Interpretation 2010-INT-05 - Interpretation of CIP-002-1 R3 for Duke Energy	Interpretation of CIP-002-1, R3		2/8/12	3/23/12	Yes 3/23/12
78.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR -002 for Constellation	Interpretation of VAR -002		2/8/12	3/23/12	Yes 3/23/12
79.	Project 2007-17	Project 2007-17 Protection System Maintenance and Testing - PRC-005	PRC-005-2		2/28/12	3/28/12	Yes 3/28/12
80.	Project 2007-09	Project 2007-09 Generator Verification - MOD-026-1 and PRC-024-1	MOD-026-1 and PRC-024-1		2/29/12	3/29/12	Yes 3/29/12
81.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - FAC-003-X, FAC-003-3	FAC-003-X FAC-003-3		3/9/12	4/9/12	Yes 4/9/12
82.	Project 2007-09	Project 2007-09 Generator Verification - MOD-025-2, MOD-027-1, and PRC-019-1	MOD-025-2 MOD-027-1 PRC-019-1		2/29/12	4/16/12	Yes 4/16/12
83.	Project 2010-07	Project 2010-07 - Generator Requirements at the Transmission Interface - PRC-005-1.1a	PRC-005-1.1a		3/2/12	4/16/12	Yes 4/16/12
84.	Project 2007-03	Project 2007-03 - Real-time Transmission Operations	TOP-001 through TOP-008 and PER-001		3/22/12	4/20/12	Yes 4/20/12
85.	Project 2012-INT-02	Request for Interpretation - Project 2012-INT-02 TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		4/24/12	5/4/12	
86.	Project 2008-06	Project 2008-06 - Cyber Security Order 706 Version 5 CIP	CIP-002 and CIP-003 - Comment Form A		4/12/12	5/21/12	Yes 5/20/12
			CIP-004 thru CIP-007 - Comment Form B		4/12/12	5/21/12	Yes 5/20/12
			CIP-008 thru CIP-011 - Comment Form C		4/12/12	5/21/12	Yes 5/20/12

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			Definitions and Implementation Plan - Comment Form D		4/12/12	5/21/12	Yes 5/20/12
87.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		4/25/12	5/24/12	Yes 5/24/12
88.	Project 2007-12	Project 2007-12 Frequency Response Technical Conferences			5/30/12	6/15/12	
89.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003		5/7/12	6/20/12	Yes 6/20/12
90.	N/A	Adequate Level of Reliability Revised Definition and Associated Documents	Adequate Level of Reliability (ALR)		4/25/12	6/25/12	Yes 6/25/12
91.	N/A	Order 754 - Request for Data or Information	Data Request		5/11/12	6/25/12	Yes 6/25/12
92.	Project 2011-INT-02	Project 2011-INT-02 - Interpretation of VAR - 002 for Constellation	Interpretation of VAR -002		5/22/12	6/27/12	Yes 6/27/12
93.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		5/29/12	6/27/12	Yes 6/27/12
94.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserve	BAL-001-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-002-2		6/4/12	7/3/12	Yes 7/3/12
			BAL-012-1		6/4/12	7/3/12	Yes 7/3/12
			BAL-013-1		6/4/12	7/3/12	Yes 7/3/12
95.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		5/21/12	7/5/12	Yes 7/5/12
96.	N/A	Cost Effective Analysis Process (CEAP) for NERC ERO Standards	CEAP		5/7/12	7/6/12	Yes 7/6/12
97.	Project 2006-06	Project 2006-06 - Reliability Coordination - COM-001, COM-002 and IRO-001-3	COM-001, COM-002 and IRO-001-3		6/7/12	7/6/12	Yes 7/6/12
98.	Project 2006-02	Project 2006-02 – Assess Transmission Future Needs and Develop Transmission Plans	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		6/19/12	7/9/12	Yes 7/9/12

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99.	N/A	Standard Processes Manual Revisions to Implement SPIG Recommendations	SPIG Reco		6/20/12	7/19/12	Yes 7/19/12
100.	Project 2012-INT-02	Project 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for System Protection and Control Subcommittee	- Interpretation of TPL-003-0a and TPL-004-0		6/20/12	7/20/12	Yes 7/19/12
101.	Project 2012-INT-05	Interpretation of 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		6/27/12	7/27/12	Yes 7/27/12
102.	Project 2011-INT-02	Project 2011-INT-02 - Rapid Revision to Address Interpretation of VAR-002 for Constellation	Rapid Revision to VAR-002		7/18/12	7/27/12	Yes 7/26/12
103.	Project 2010-INT-01	Project 2010-INT-01 - Rapid Revision of TOP-006 for FMPP	Rapid Revision of TOP-006		6/14/12	7/30/12	Yes 7/27/12
104.	Project 2012-08.1	Project 2012-08.1 - Phase 1 of Glossary Updates: Statutory Definitions	Glossary of Terms		6/19/12	8/2/12	Yes 8/2/12
105.	N/A	Reliability Guideline: System Operator Verbal Communications – Current Industry Practices	System Operator Verbal Communications		6/26/12	8/10/12	Yes 8/9/12
106.	Project 2007-17	Project 2007-17 - Protection System Maintenance and Testing - PRC-005	PRC-005-2		7/27/12	8/27/12	Yes 8/27/12
107.	Project 2010-11	Project 2010-11 - TPL Table 1 Order TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12	TPL-002-1b, footnote ‘b’ and TPL-001-3, footnote 12		7/31/12	8/29/12	Yes 8/29/12
108.	Project 2006-02	Project 2006-02 - Assess Transmission and Future Needs			7/31/12	8/30/12	
109.	Project 2009-19	Project 2009-19 – Interpretation of BAL-002 by NWPP Reserve Sharing Group			7/25/12	9/4/12	
110.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		8/3/12	9/4/12	Yes 9/4/12
111.	Project 2010-05.1	Project 2010-05.1 - Protection Systems: Phase 1 (Misoperations)			7/25/12	9/7/12	Yes 9/7/12

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112.	N/A	Definition of Adequate Level of Reliability	Adequate Level of Reliability (ALR)		8/15/12	9/13/12	Yes 9/13/12
113.	N/A	2013-2015 Reliability Standards Development Plan	2013-2015 RSDP		8/17/12	9/18/12	Yes 9/18/12
114.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols	COM-003-1		8/22/12	9/20/12	Yes 9/20/12
115.	Project 2009-01	Project 2009-01 - Disturbance and Sabotage Reporting	EOP-004-2		8/29/12	9/27/12	
116.	SPP Regional Standard	Regional Reliability Standard PRC-006-SPP-01 Automatic Underfrequency Load Shedding	PRC-006-SPP-01		8/15/12	9/28/12	
117.	Project 2008-06 Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		9/11/12	10/10/12	Yes 10/10/12
			RSAW		9/11/12	10/10/12	Yes 10/10/12
118.	MRO SPM	Regional Reliability Standards - MRO Standards Process Manual			8/28/12	10/11/12	
119.	N/A	Standard Process Manual Revisions to Implement SPIG Recommendations	SPIG Reco		8/29/12	10/12/12	Yes 10/10/12
120.		Revisions to Outstanding VRFs and VSLs			9/5/12	10/19/12	
121.	Project 2013-01	Project 2013-01 - Cold Weather Preparedness			9/25/12	10/24/12	
122.	Project 2007-09	Project 2007-09 - Generator Verification			9/28/12	10/29/12	
123.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System			10/4/12	11/5/12	
124.	2007-12	Project 2007-12 - Frequency Response			10/5/12	11/7/12	
125.	Project 2008-06	Project 2008-06 - Cyber Security - Order 706 - CIP-002-5 through CIP-009-5, CIP-010-1, and CIP-011-1	Version 5 CIP Standards		10/26/12	11/7/12	
126.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025		10/5/12	11/7/12	

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127.	N/A	IRO-006-WECC-2			10/3/12	11/16/12	
128.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B			10/5/12	11/19/12	
129.	Project 2012-INT-02	Interpretation 2012-INT-02 - Interpretation of TPL-003-0a and TPL-004-0 for SPCS	Interpretation of TPL-003-0a and TPL-004-0		10/22/12	12/5/12	Yes 12/5/12
130.	Project 2013-02	Project 2013-02 - Paragraph 81	Paragraph 81		10/25/12	12/10/12	Yes 12/10/12
131.	Project 2012-INT-06	Project 2012-INT-06 - Interpretation of CIP-003-3 for Consumers Energy	- Interpretation of CIP-003-3		11/9/12	12/10/12	Yes 12/10/12
132.	Project 2012-INT-04	Project 2012-INT-04 - Interpretation of CIP-007-3 for ITC	- Interpretation of CIP-007-3		11/9/12	12/10/12	Yes 12/10/12
133.	Project 2007-02	Project 2007-02 - Operating Personnel Communication Protocols - RSAW	COM-003-1		11/14/12	12/13/12	Yes 12/13/12
			COM-003-1 RSAW		11/14/12	12/13/12	Yes 12/13/12
134.	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-001 and PRC-027		11/16/12	12/17/12	Yes 12/17/12
135.	Project 2012-INT-05	Project 2012-INT-05 - Interpretation of CIP-002-3 for OGE	Interpretation of CIP-002-3		11/6/12	12/20/12	Yes 12/20/12
136.	N/A	Standard Processes Manual to Implement SPIG Revisions	SPIG Reco		11/21/12	12/20/12	Yes 12/20/12
137.	Project 2010-11	Project 2010-11 - TPL Table 1, Footnote B	TPL-002-1b, footnote 'b' and TPL-001-3, footnote 12		12/10/12	1/11/13	Yes 1/11/13
138.	Project 2007-09	Project 2007-09 - Generator Verification - PRC-024-1	PRC-024-1		12/12/12	1/11/13	Yes 1/11/13
139.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-012-1	BAL-012-1		11/30/12	1/14/13	Yes 1/14/13
140.	N/A	Reliability Guideline--Draft Generating Unit Winter Weather Readiness - Current Industry Practices			12/20/12	2/4/13	Yes 2/4/13
141.	Project 2010-05-1	Project 2010-05-1 Protection System Misoperations					Yes 2/20/13
142.	Project 2007-09	Project 2007-09 Generator Verification - PRC-024-1	PRC-024-1	Formal	1/25/13	2/25/13	Yes 2/25/13

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143.	N/A	Rapid Revision Procedure		Informal	2/25/13	3/6/13	Yes 3/6/13
144.	Project 2010-13-2	Project 2010-13-2 - Phase 2 of Relay Loadability - Generation - PRC-025-1	PRC-025-1	Formal	1/25/13	3/11/13	Yes 3/11/13
			Supplemental SAR	Informal	1/25/13	3/11/13	Yes 3/11/13
			Cost Effectiveness	CEAP Pilot	1/25/13	3/11/13	Yes 3/11/13
			RSAW	Feedback	1/25/13	3/11/13	Yes 3/11/13
145.	Project 2012-INT-04	Interpretation 2012-INT-04 - Interpretation of CIP-007 for ITC	Interpretation of CIP-007	Formal	2/6/13	3/22/13	Yes 3/22/13
146.	Project 2012-INT-06	Interpretation 2012-INT-06 - Interpretation of CIP-003 for Consumers Energy	Interpretation of CIP-003	Formal	2/6/13	3/22/13	Yes 3/22/13
147.	Project 2012-08-1	Project 2012-08-1 - Phase 1 of Glossary Updates--Statutory Definitions	Glossary of Terms	Formal	2/21/13	3/22/13	Yes 3/22/13
148.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003-1	COM-003-1	Formal	3/7/13	4/5/13	Yes 4/5/13
			RSAW	Feedback	3/7/13	4/5/13	Yes 4/5/13
149.	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-001-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-002-2	Formal	3/12/13	4/25/13	Yes 4/25/13
			BAL-013-1	Formal	3/12/13	4/25/13	Yes 4/25/13
150.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays)	Draft SAR	Informal	4/5/13	5/6/13	Yes 5/6/13
			PRC-005-3	Formal	4/5/13	5/6/13	Yes 5/613
151.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation	PRC-023-3 PRC-025-1	Formal	4/25/13	5/24/13	Yes 5/24/13
152.	Project 2007-11	Project 2007-11 - Disturbance Monitoring — PRC-002 and PRC-018	SAR	Informal	5/03/13	6/03/13	Yes 6/3/13
153.	Project 2007-11	Project 2007-11 - Disturbance Monitoring PRC-002 and PRC-018	Request for Information	Informal	6/05/13	7/05/13	
154.	Project 2007-06	Project 2007-06 - System Protection Coordination - PRC-001 and PRC-027	PRC-001 and PRC-027		6/04/13	7/03/13	Yes 7/03/13

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155.	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System (Phase 2)	BES Definition		5/29/13	7/12/13	Yes 7/12/13
156.	TRE Regional Standard	Regional Reliability Standard - BAL-001-TRE-01	BAL-001-TRE-01		5/31/13	7/15/13	
157.	N/A	NPCC Regional Standards Process Manual	NPCC RSPM		6/06/13	7/22/13	
158.	Project 2007-02	Project 2007-02 - Operating Personnel Communications Protocols - COM-003	COM-003-1		6/20/13	7/19/13	Yes 7/19/13
159.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-025	PRC-025-1		6/20/13	7/19/13	Yes 7/19/13
160.	Project 2010-13.2	Project 2010-13.2 - Phase 2 of Relay Loadability: Generation - PRC-023	PRC-023-3	Formal	6/20/13	8/05/13	Yes 8/5/13
161.	N/A	SPP RE Regional Standards Process Manual	SPP RSPM		6/26/13	8/09/13	
162.	Project 2013-03	Project 2013-03 - Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	6/27/13	8/12/13	Yes 8/12/13
163.	Project 2007-17.2	Project 2007-17.2 - Protection System Maintenance and Testing - Phase 2 (Reclosing Relays) - PRC-005	PRC-005-3	Formal	7/10/13	8/23/13	Yes 8/23/13
164.	Project 2008-12	Project 2008-12 - Coordinate Interchange Standards - Various INT standards	INT-004-3 INT-006-4 INT-009-2 INT-010-2 INT-011-1	Informal	7/25/13	8/23/13	Yes 8/23/13
165.	Project 2012-05	Project 2012-05 ATC Revisions (MOD A) - MOD-001-2	MOD-001-2	Formal	7/11/13	8/26/13	Yes 8/26/13
166.	Project 2010-01	Project 2010-01 - Training - PER-005-2	PER-005-2	Formal	7/19/13	9/03/13	Yes 9/3/13
167.	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-001-4 VAR-002-3	Formal	7/19/13	9/03/13	Yes 9/3/13
168	Project 2010-03	Project 2010-03 - Modeling Data (MOD B) - MOD-032-1, MOD-033-1	MOD-032-1 MOD-033-1	Formal	7/22/13	9/04/13	Yes 9/4/13

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169.	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	7/22/13	9/04/13	Yes 9/4/13
170	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System – Phase 2	BES Definition Phase 2	Formal	8/6/13	9/4/13	Yes 9/4/13
171	Project 2012-13	Project 2012-13 - NUC Five-Year Review	NUC-001-2	5-year review	7/26/13	9/9/13	Yes 9/9/13
172	2014-2016 RSDP	2014-2016 Reliability Standards Development Plan	Reliability Standards Development Plan	Annual Review	8/30/13	9/13/13	Yes 9/13/13
173	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-001-1 FAC-002-1	5-year review	8/1/13	9/16/13	Yes 9/16/13
174	Project 2010-02	Project 2010-02 Five-Year Review of FAC Standards	FAC-003-3 FAC-008-3 FAC-010-2.1 FAC-011-2 FAC-013-2 FAC-014-2	5-year review	8/1/13	9/16/13	Yes 9/16/13
175	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves - BAL-002-2, BAL-013-1	BAL-002-2	Formal	8/2/13	9/16/13	Yes 9/16/13
176	Project 2009-03	Project 2009-03 — Five-Year Review of Emergency Operations EOP-001, EOP-002, EOP-003, and IRO-001	EOP-001-2.1b EOP-002-3.1 EOP-003-2	5-year review	8/6/13	9/19/13	Yes 9/19/13
177	Project 2012-09	Project 2012-09 IRO Five-Year Review	IRO-003-2 IRO-004-2 IRO-005-4 IRO-006-5 IRO-006-East IRO-008-1 IRO-009-1 IRO-010-1a	5-year review	8/7/13	9/20/13	Yes 9/20/13
178	Project 2008-02	Project 2008-02 Undervoltage Load Shedding	Revised SAR	Informal	9/10/13	10/9/13	Yes 10/9/13
179	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	EOP-010-1	Formal	9/4/13	10/18/13	Yes 10/18/13
180	Project 2010-17	Project 2010-17 - Definition of Bulk Electric System	BES Definition	Formal	9/27/13	10/28/13	Yes 10/28/13

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181	Project 2007-02	Project 2007-02 Operating Personnel Communications Protocols	COM-002-4	Formal	10/21/13	11/7/13	Yes 11/4/13
182	Project 2010-01	Project 2010-01 Training	PER-005-2	Formal	9/27/13	11/12/13	Yes 11/12/13
183	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	Various INT Standards	Formal	9/30/13	11/13/13	Yes 11/13/13
184	Project 2012-05	Project 2012-05 ATC Revisions (MOD A)	MOD-001-2	Formal	10/4/13	11/20/13	Yes 11/18/13
185	Project 2010-03	Project 2010-03 Modeling Data (MOD B)	MOD-032-1, MOD-033-1	Formal	10/07/13	11/20/13	
186	Project 2010-04	Project 2010-04 Demand Data (MOD C)	MOD-031-1	Formal	10/09/13	11/22/13	Yes 11/22/13
187	Project 2013-04	Project 2013-04 Voltage and Reactive Control	VAR-001-4, VAR-002-3	Formal	10/11/13	11/25/13	Yes 11/25/13
188	Project 2009-03	Project 2009-03 Emergency Operations	SAR	Informal	11/06/13	12/05/13	Yes 12/5/13
189	Project 2010-14.1	Project 2010-14.1 - Phase 1 of Balancing Authority Reliability-based Controls: Reserves	BAL-002-2	Formal	10/28/13	12/11/13	Yes 12/11/13
190	Project 2007-11	Project 2007-11 - Disturbance Monitoring	PRC-002-2	Formal	11/01/13	12/16/13	Yes 12/16/13
191	Project 2007-06	Project 2007-06 - System Protection Coordination	PRC-027	Formal	11/04/13	12/18/13	Yes 12/18/13
192	Project 2014-01	Project 2014-01 - Standards Applicability for Dispersed Generation Resources	SAR	Formal	11/20/13	12/19/13	Yes 12/19/13
193	Project 2010-01	Project 2010-01 Training - PER-005-2	PER-005-2	Formal	12/4/13	1/22/14	Yes 1/17/14
194	Project 2010-03	Project 2010-03 Modeling Date - MOD B	MOD-033-1	Formal	12/6/13	1/22/14	Yes 1/21/14
195	Project 2008-12	Project 2008-12 Coordinate Interchange Standards	INT-004-3 INT-010-2	Formal	1/10/14	1/24/14	Yes 1/22/14
196	Project 2007-02	Project 2007-02 Operating Personnel	COM-002-4	Formal	1/22/14	1/31/14	Yes 1/31/14
197	Project 2014-02	Project 2014-02 Standard Authorization Request – Cyber Security Standards	CIP SAR	Informal	1/17/14	2/18/14	Yes 2/18/14
198	2014 Work Plan	2014 Work Plan for NERC Reliability Standards Development	2014 Work plan			2/21/13	Yes 2/21/14

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199	Project 2010-17	Project 2010-17 Definition of Bulk Electric System - Phase 2	BES	Informal	1/29/14	2/27/14	Yes 2/27/14
200	Project 2010-05.1	Project 2010-05.1 Protection System: Phase 1 (Misoperations) - PRC-004-3	PRC-004-3	Formal	1/17/14	3/11/14	Yes 3/2/14
201	Project 2012-13	Project 2012-13 NUC-Nuclear Plant Interface Coordination Standard Authorization Request	NUC-001-2.1 SAR	Informal	2/12/14	3/13/14	Yes 3/13/14
202	Project 2010-05.2	Project 2010-05.2 Special Protection Systems (Phase 2 of Protection Systems) - SAR	SAR	Informal	2/18/14	3/19/14	Yes 3/19/14
203	Project 2014-03	Project 2014-03 - Revisions to TOP/IRO Reliability Standards	SAR	Formal	02/21/14	03/24/14	Yes 3/24/14
204	Project 2014-03	Technical Conferences on Revisions to TOP/IRO Reliability Standards	Technical Conference Topics	Informal	03/11/14	03/24/14	
205	Project 2014-04	Project 2014-04 - Physical Security	SAR	Informal	03/21/14	03/28/14	Yes 3/28/14
206	Project 2010-14.2	Project 2010-14.2 - Periodic Review of BAL Standards	Reco to Revise BAL-005 and BAL-006	Formal	02/21/14	04/07/14	
207	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Informal	03/11/14	04/09/14	Yes 4/9/14
208	Project 2010-04	Project 2010-04 - Demand Data (MOD C) - MOD-031-1	MOD-031-1	Formal	02/25/14	04/10/14	Yes 4/10/14
209	Project 2013-04	Project 2013-04 Voltage and Reactive Control - VAR-001-4, VAR-002-3	VAR-002-3	Formal	02/27/14	04/14/14	Yes 4/14/14
210	Project 2008-02	Project 2008-02 - Undervoltage Load Shedding - PRC-010, PRC-020, PRC-021 and PRC-022	PRC-010-1	Informal	03/17/14	04/16/14	Yes 4/16/14
211	Project 2014-04	Project 2014-04 Physical Security - CIP-014-1	CIP-014-1	Formal	04/10/14	04/24/14	Yes 4/24/14
212	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Informal	03/28/14	04/28/14	Yes 4/28/14

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213	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	04/17/14	05/05/14	Yes 5/5/14
214	Project 2010-02	Project 2010-02 – Connecting New Facilities to the Grid	FAC-001-1 FAC-002-1	Formal	04/01/14	05/15/14	Yes 5/15/14
215	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Informal	04/22/14	05/21/14	Yes 5/21/14
216	Project 2012-13	Project 2012-13 Nuclear Plant Interface Coordination	NUC-001-3	Formal	04/08/14	05/22/14	Yes 5/22/14
217	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays)	PRC-005-X	Formal	04/17/14	06/03/14	Yes 6/3/14
218	Project 2010-13.3	Project 2010-13.3 Relay Loadability: Stable Power Swings	PRC-026-1	Formal	04/25/14	06/09/14	Yes 6/9/14
219	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	05/09/14	06/25/14	Yes 6/25/14
221	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Informal	05/23/14	06/23/14	Yes 6/23/14
222	Project 2010-05-1	Project 2010-05-1 Protection System – Phase 1 – Misoperations	PRC-004	Formal	05/16/14	07/09/14	Yes 7/9/14
223	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	05/19/14	07/02/14	Yes 7/2/14
224	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-002 to CIP-011	Formal	06/02/14	07/17/14	Yes 7/16/14
225	Project 2015-2017	Project 2015-2017 Reliability Standard		Informal		7/21/14	Yes 7/21/14

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		Development Plan					
226	2010-05.2	Project 2010-05.2 - Phase 2 of Protection Systems - Revised Definition of Special Protection System	SPS Definition	Formal	7/16/14	7/25/14	Yes 7/25/14
227	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-2(X) PRC-005-3(X) PRC-005-X(X) VAR-002-2b(X) VAR-002-4	Formal	06/12/14	7/29/14	Yes 7/29/14
228	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	06/13/14	07/30/14	Yes 7/30/14
229	Project 2008-02	Project 2008-02 Undervoltage Load Shedding and Underfrequency Load Shedding	PRC-010 PRC-020 PRC-021 PRC-022	Formal	06/23/14	08/8/14	Yes 8/6/14
230	Project 2010-14-2	Project 2010-14-2 Balancing Authority Reliability-based Control Standard Authorization Request for BAL-005 and BAL-006	BAL-005 BAL-006	Informal	07/16/14	08/14/14	Yes 8/12/14
231	Project 2009-03	Project 2009-03 Emergency Operations – EOP-011-1	EOP-011-1	Formal	07/2/14	08/15/14	Yes 8/13/14
232	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-004-2.1a(X) PRC-004-3(X)	Formal	07/10/14	08/26/14	Yes 8/25/14
233	Project 2007-17.3	Project 2007-17.3 Protection System Maintenance and Testing – Phase 3 (Sudden Pressure Relays) – PRC-005-X	PRC-005-X	Formal	07/30/14	09/12/14	Yes 9/12/14
234	Project 2014-03	Project 2014-03 Revisions to TOP-IRO Reliability Standards	TOP-001-3 TOP-002-4 TOP-003-3 IRO-001-4 IRO-002-4 IRO-008-2 IRO-010-2 IRO-014-3 IRO-017-1	Formal	08/6/14	09/19/14	Yes 9/22/14
235	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	08/19/14	10/03/14	Yes 10/2/14

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236	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	09/26/14	10/06/14	Yes 10/6/14
237	Project 2008-02	Project 2008-02: Underfrequency Load Shedding (UFLS)	PRC-006-2	Formal	08/21/14	10/08/14	Yes 10/7/14
238	Project 2013-03	Project 2013-03: Geomagnetic Disturbance Mitigation	TPL-007-1	Formal	08/27/14	10/10/14	Yes 10/10/14
239	NERC Rules of Procedure	NERC Rules of Procedure	NERC Rules of Procedure	Formal	08/26/14	10/10/14	Yes 10/14/14
240	Project 2010-05.2	Project 2010-05.2 – Special Protection Systems Phase 2 of Protection Systems	RAS Definition	Formal	08/29/14	10/14/14	Yes 10/14/14
241	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	VAR-002-2b(X) VAR-002-4	Formal	08/27/14	10/16/14	Yes 10/16/14
242	Project 2014-02	Project 2014-02 CIP Version 5 Revisions – Cyber Security Standards	CIP-003-6 CIP-010-2 CIP-003-X CIP-004-X CIP-007-X CIP-010-X CIP-011-X	Formal	09/03/14	10/17/14	Yes 10/17/14
243	Project 2009-03	Project 2009-03 Emergency Operations	EOP-011-1	Formal	09/05/14	10/20/14	Yes 10/20/14
244	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Preliminary Draft 5)	PRC-027-1	Informal	10/01/14	10/21/14	Yes 10/21/14
245	Project 2007-11	Project 2007-11 Disturbance Monitoring	PRC-002-2	Formal	09/05/14	10/21/14	Yes 10/21/14
246	Project 2014-01	Project 2014-01 Applicability for Dispersed Generation	PRC-004-2.1a(X) PRC-004-4	Formal	09/05/14	10/22/14	Yes 10/22/14
247	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	10/10/14	11/10/14	Yes 11/10/14
248	Project 2013-03	Project 2013-03 Geomagnetic Disturbance Mitigation TPL-007-1	TPL-007-1	Formal	10/28/14	11/21/14	Yes 11/24/14
249	Project 2010-13.3	Project 2010-13.3 – Relay Loadability: Stable Power Swings	PRC-026-1	Formal	11/04/14	11/24/14	Yes 11/25/14
250	Project 2014-01	Project 2014-01 – Standards Applicability	PRC-001-1.1 PRC-019-2	Formal	11/05/14	12/23/14	Yes 12/22/14

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		for Dispersed Generation Resources	PRC-024-1				
251	Project 2014-03	Project 2014-03 Revisions to TOP/IRO Reliability Standards TOP-001-3	TOP-001-3	Formal	12/29/14	1/7/15	Yes 1/6/15
252	Project 2014-02	Project 2014-02 CIP Version 5 Revisions	CIP-003-7 CIP-004-7 CIP-007-7 CIP-010-3 CIP-011-3 CIP-003-7 CIP-010-3 Implementation Plan	Formal	12/30/14	1/9/15	Yes 1/9/15
253	Project 2014-04	Project 2014-04 Physical Security SAR	SAR	Informal	12/15/14	1/13/15	Yes 1/12/15
254	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	White Paper Appendix A Appendix B	Informal	12/22/14	1/20/15	Yes 1/20/15
255	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generation Resources	PRC-005-5	Informal	12/22/14	1/20/15	Yes 1/22/15
257	Project 2010-14.1	Project 2010-14.1 Balancing Authority Reliability-based Control	BAL-002-2	Formal	1/29/15	3/18/15	Yes 3/16/15
258	Reliability Guideline	Reliability Guideline: Loss of Real-Time Reliability Tools Capability/Loss of Equipment Significantly Affecting ICCP Data		Formal	2/19/15	4/6/15	Yes 4/6/15
259	Project 2008-02.2	Project 2008-02.2 Phase 2 UVLS: Misoperation	PRC-010-2	Formal	2/20/15	4/7/15	Yes 4/7/15
260	Project 2014-04	Project 2014-04 Physical Security	CIP-014-2	Formal	2/20/15	4/9/15	Yes 4/9/15
261	Project 2015-04	Project 2015-04 Alignment of Terms	SAR	Formal	2/24/15	4/13/15	Yes 4/13/15
262	Project 2007-17.4	Project 2007-17.4 PRC-005 Order No. 803 Directives	SAR	Informal	3/12/15	4/10/15	Yes 4/13/15
263	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	SAR	Informal	3/16/15	4//15/15	Yes 4/15/15
264	Project 2010-14.2.2	Project 2010-14.2.2 Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	SAR	Informal	3/17/15	4//15/15	Yes 4/15/15

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(As of 12/1/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
265	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-008-1	Informal	3/27/15	5/11/15	Yes 5/11/15
266	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-006-2	Informal	3/27/15	5/11/15	Yes 5/11/15
267	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-005-2	Informal	3/27/15	5/11/15	Yes 5/11/15
268	Project 2015-02	Project 2015-02 Periodic Review of Emergency Operations	EOP-004-2	Informal	3/27/15	5/11/15	Yes 5/11/15
269	Project 2007-06	Project 2007-06 System Protection Coordination PRC-027-1 (Draft 5)	PRC-027-1	Formal	4/1/15	5/15/15	Yes 5/15/15
270	Project 2010-04.1	Project 2010-04.1 MOD-031 FERC Order No. 804 Directives	SAR	Informal	4/16/15	5/19/15	Yes 5/19/15
271	Project 2010-05.3	Project 2010-05.3 Phase 3 of Protection Systems – RAS	PRC-012-2	Informal	4/30/15	5/20/15	Yes 5/20/15
272	Project 2015-03	Project 2015-03 Periodic Review of System Operating Limit Standards	FAC-010-3 FAC-011-3 FAC-014-2	Formal	5/4/15	6/17/15	Yes 6/17/15
273	Project 2015-06	Project 2015-06 Interconnection Reliability Operations and Coordination	IRO-006-East-2 IRO-009-2	Formal	5/21/15	7/8/15	Yes 7/8/15
274	Project 2007-17.4	Project 2007-17.4 PRC-005 FERC Order No. 803 Directive	PRC-005-3	Formal	6/11/15	7/10/15	Yes 7/10/15
275	Project 2014-01	Project 2014-01 Standards Applicability for Dispersed Generations Resources	PRC-004-2.1 PRC-005-2 PRC-005-3	Informal	6/12/15	7/13/15	Yes 7/13/15
276	Project 2015-07	Project 2015-07 Internal Communications Capabilities	COM-001-2	Informal	6/11/15	7/15/15	Yes 7/15/15
277	Project 2015-04	Alignment of Terms	Glossary Terms	Formal	6/12/15	7/23/15	Yes 7/23/15
278	Project 2009-02	Real-time Monitoring and Analysis Capabilities	SAR	Formal	7/16/15	8/17/15	Yes 8/17/15
279	NERC 2016-2018	Reliability Standards Development Plan	Development Plan	Formal	7/16/15	8/17/15	Yes 8/17/15
280	Project 2015-08	Emergency Operations	EOP-004-2 EOP-005-2 EOP-006-2 EOP-008-1	Informal	7/21/15	8/19/15	Yes 8/19/15
281	Project 2010-14.1	Phase 1 of Balancing Authority Reliability-	BAL-002-2	Formal	7/7/15	8/20/15	Yes 8/20/15

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
		based Controls					
282	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls: Time Error Correction	BAL-004-0	Survey	8/12/15	8/25/15	Yes 8/25/15
283	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	7/29/15	9/11/15	Yes 9/11/15
284	Project 2007-06	System Protection Coordination	PRC-027-1	Formal	7/29/15	9/11/15	Yes 9/11/15
285	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 BAL-006-3	Formal	7/30/15	9/14/15	Yes 9/14/15
286	Project 2007-17.4	PRC-005 FERC Order No. 803 Directive	PRC-005-6	Formal	7/30/15	9/16/15	Yes 9/16/15
287	Project 2010-04.1	MOD-031 FERC Order No. 804 Directives	MOD-031-2	Formal	7/31/15	9/18/15	Yes 9/18/15
288	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010-3 FAC-011-3 FAC-014-2	Informal	8/20/15	9/21/15	Yes 9/21/15
289	Project 2010-07.1	Vegetation Management	FAC-003-3	Informal	8/24/15	9/28/15	Yes 9/28/15
290	Project 2010-05.3	Phase 3 of Protection Systems: Remedial Action Schemes	PRC-012-2	Formal	8/20/15	10/5/15	Yes 10/5/15
291	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	9/24/15	11/9/15	Yes 11/9/15
292	Project 2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Controls	BAL-004-0	Formal	9/24/15	11/12/15	Yes 11/12/15
293	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	9/25/15	11/16/15	Yes 11/16/15
294	Project 2007-06.2	Phase 2 of System Protection Coordination	TOP-009-1	Formal	10/6/15	11/19/15	Yes 11/19/15
295	Project 2010-07.1	Vegetation Management	FAC-003-3	Formal	10/30/15	12/16/15	Yes 12/16/15
296	Project 2015-10	Single Points of Failure SAR	TPL-001	Informal	11/12/15	12/17/15	Yes 12/17/15
297	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	11/25/15	1/8/16	Yes 1/8/16
298	Project 2010-14.2.1	Phase 2 of Balancing Authority Reliability-based Controls	BAL-005-1 FAC-001-3 BAL-006-2	Formal	12/31/15	1/11/16	Yes 1/11/16
299	Project 2009-02	Real-time Reliability Monitoring and Analysis Capabilities	IRO-018-1 TOP-010-1	Formal	12/10/15	1/25/16	Yes 1/25/16
300	Project 2016-01	Modifications to TOP and IRO Standards	SAR	Informal	1/22/16	2/22/16	Yes 2/22/16
301	Project 2010-05.3	Phase 3 of Protection Systems RAS	PRC-012-2	Formal	2/3/16	3/18/16	Yes 3/18/16
302	Project	Modifications to CIP	SAR	Informal	3/23/16	4/21/16	Yes

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(As of 12/1/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					4/21/16
303	Project 2007-06.2	Phase 2 of System Protection Coordination	PER-006-1 & Two Definitions	Formal	3/10/16	4/25/16	Yes 4/25/16
304	Project 2015-07	Internal Communications Capabilities	COM-001-3	Formal	3/23/16	5/9/16	Yes 5/6/16
305	CEP	Cost Effectiveness Pilot	TPL-001-4	Informal	4/27/16	5/26/16	Yes 5/26/16
306	Project 2013-03	Geomagnetic Disturbance Mitigation Revised White Papers	SAR	Informal	5/12/16	6/13/16	Yes 6/13/16
307	Project 2015-10	Single Points of Failure	SAR	Informal	5/26/16	6/24/16	Yes 6/24/16
308	Project 2016-02	Modifications to CIP Standards	SAR	Informal	6/1/16	6/30/16	Yes 6/30/16
309	Draft 2017-2019	Reliability Standards Development Plan	RSDP	Informal	6/20/16	7/19/16	Yes 7/19/16
310	EPR	Enhanced Periodic Review Standing Review Team	Standards Grading	Informal	6/30/16	8/1/16	Yes 8/1/16
311	Project 2016-01	Modifications to TOP and IRO Standards	IRO-002-5 TOP-001-4	Formal	6/20/16	8/3/16	Yes 8/3/16
312	Project 2015-09	Establish and Communicate System Operating Limits	FAC-014-3	Formal	7/14/16	8/12/16	Yes 8/12/16
313	Project 2015-09	Establish and Communicate System Operating Limits	FAC-011-4	Formal	7/14/16	8/12/16	Yes 8/12/16
314	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3 EOP-008-2	Formal	6/30/16	8/15/16	Yes 8/15/16
315	Project 2016-02	Modifications to CIP Standards	CIP-003-7	Formal	7/21/16	9/6/16	Yes 9/6/16
316	FMAG	Functional Model Advisory Group	Reliability Functional Model and Technical Document	Informal	7/21/16	9/7/16	Yes 9/7/16
317	Project 2015-08	Emergency Operations	EOP-004-4	Formal	7/25/16	9/8/16	Yes 9/8/16
318	Project 2015-INT-01	Interpretation of CIP-002-5.1 for Energy Sector Security Consortium (EnergySec)	CIP-002-5.1	Formal	7/27/16	9/12/16	Yes 9/12/16
319	Project 2016-01	Modifications to TOP and IRO Standards SAR	TOP-001-3 IRO-002-4	Formal	8/31/16	10/17/16	Yes 10/14/16
320	Project 2016-04	Modifications to PRC-025-1 SAR	PRC-025-1	Formal	9/16/16	10/18/16	Yes 10/18/16
321	Project 2016-03	Cyber Security Supply Chain Management	SAR	Informal	10/20/16	11/18/16	Yes 11/18/16
322	Project	Modifications of CIP	CIP-003-TCA	Informal	11/1/16	11/18/16	Yes

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
	2016-02	Standards					11/18/16
323	Project 2016-02	Modifications of CIP Standards	CIP-003-7	Formal	11/23/16	12/5/16	Yes 12/5/16
324	Project 2015-08	Emergency Operations	EOP-005-3 EOP-006-3	Formal	10/26/16	12/9/16	Yes 12/9/16
325	Project 2015-08	Emergency Operations	EOP-004-4	Formal	11/18/16	1/6/17	Yes 1/6/17
326	Project 2013-03	Geomagnetic Disturbance Mitigation	SAR	Informal	12/16/16	1/20/17	Yes 1/20/17
327	Project 2016-02	Modifications of CIP Standards	CIP-003-7(i)	Formal	12/12/16	1/25/17	Yes 1/25/17
328	Project 2016-EPR-01	Enhanced Periodic Review of Personnel Performance, Training and Qualifications Standard (PER)	PER-001-0.2 PER-003-1 PER-004-2	Formal	1/10/17	2/23/17	Yes 2/23/17
329	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-013-1	Formal	1/19/17	3/6/17	Yes 3/6/17
330	Project 2016-04	Modifications to PRC-025-1	SAR	Informal	3/20/17	4/3/17	Yes 4/3/17
331	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	3/14/17	4/11/17	Yes 4/11/17
332	Project 2016-02	Modifications to CIP Standard	TOCC	Informal	3/14/17	4/11/17	Yes 4/11/17
333	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-001-4.1	Formal	2/28/17	4/13/17	Yes 4/13/17
334	Project 2016-EPR-02	Enhanced Periodic Review of Voltage and Reactive (VAR) Standards	VAR-002-4	Formal	2/28/17	4/13/17	Yes 4/13/17
335	SPM	Revisions to the NERC Standard Processes Manual	SPM	Formal	3/20/17	5/3/17	Yes 5/3/17
336	Project 2015-10	Single Points of Failure	TPL-001-5	Informal	4/25/17	5/24/17	Yes 5/24/17
337	Project 2016-03	Cyber Security Supply Chain Risk Management	CIP-005-6 CIP-010-3 CIP-013-1	Formal	5/2/17	6/15/17	Yes 6/15/17
338	Project 2017-01	Modifications to BAL-003-1.1 SAR	BAL-003-1.1	Formal	6/19/17	7/18/17	Yes 7/18/17
339	Project 2017-06	Modifications to BAL-002-2 SAR	BAL-002-2	Informal	6/20/17	7/20/17	Yes 7/20/17
340	Project 2017-02	Modifications to Personnel Performance, Training and Qualifications Standards	PER-003-1 PER-004-2	Informal	6/21/17	7/24/17	Yes 7/24/17
341	2018-2010	Reliability Standards Development Plan		Formal	6/22/17	7/25/17	Yes 7/26/17

RSC Meeting #17-4, Agenda Item 6.3: Comment History

(As of 12/1/2017)

Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
342	Standards Grading	Periodic Review Standing Review Team	Standards Grading	Informal	6/19/17	8/2/17	Yes 8/2/17
343	Project 2013-03	Geomagnetic Disturbance Mitigation	TPL-007-2	Formal	6/28/17	8/11/17	Yes 8/11/17
344	Project 2017-07	Alignment with Registration	Registration	Formal	8/1/17	8/30/17	Yes 8/30/17
345	Project 2017-07	Alignment with Registration	MOD-032-1 SAR	Formal	8/1/17	8/30/17	Yes 8/30/17
346	Reliability Guideline	Area Control Error Diversity Interchange Process	ACE Process	Formal	7/18/17	8/31/17	Yes 8/31/17
347	Project 2016-04	Modifications to PRC-025-1	PRC-025-2	Formal	7/25/17	9/7/17	Yes 9/7/17
348	Project 2016-02	Modifications to CIP Standard	CIP-012-1	Formal	7/27/17	9/11/17	Yes 9/11/17
349	Project 2016-02	Modifications to CIP Standard	Technical Rationale and Justification for CIP-012-1	Informal	8/14/17	9/12/17	Yes 9/12/17
350	Project 2016-02	Modifications to CIP Standard	Definition of Control Center	Informal	8/14/17	9/12/17	Yes 9/12/17
351	Project 2015-10	Single Points of Failure	TPL-001-5	Formal	9/8/17	10/23/17	Yes 10/23/17
352	Project 2016-02	Modifications to CIP Standard	CIP-002-6	Formal	9//14/17	10/30/17	Yes 10/30/17
353	Project 2015-09	Establish and Communicate System Operating Limits	Proposed Definitions of System Operating Limit (SOL) and SOL Exceedance	Informal	9/29/17	10/30/17	Yes 10/30/17
354	Project 2016-02	Modifications to CIP Standard	Virtualization	Informal	10/6/17	11/2/17	Yes 11/2/17
355	Project 2015-09	Establish and Communicate System Operating Limits	FAC-010 FAC-011 FAC-014	Formal	9/29/17	11/13/17	Yes 11/13/17
356	Project 2017-01	Modifications to BAL-003-1.1	SAR	Formal	11/2/17	12/1/17	Yes 12/1/17

Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

NORTHEAST POWER COORDINATING COUNCIL, INC.
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PRC-006-NPCC-02 Automatic Underfrequency Load Shedding

CONFERENCE CALL #2

November 6, 2017 1:30 p.m. – 4:00 p.m. EST

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada)
Guest Code: 319190445
Password: CjjCD?53 (25523053 from phones)

	Name	Organization
1.	Guy Zito	Northeast Power Coordinating Council
2.	Ruida Shu	Northeast Power Coordinating Council
3.	Juan Villar	FERC
4.	Dan Taft	Con Edison
5.	Vincent Morissette	Hydro Québec TransÉnergie
6.	Jeannette Gauthier	Hydro Québec TransÉnergie
7.	Dean Latulipe	National Grid
8.	Brian Robinson	Utility Services
9.	Daniel Kidney	Northeast Power Coordinating Council
10.	Nick Parrotta	PLM
11.	John Pearson	ISO-NE

Introductions and Chair's Remarks
Dan Taft called the meeting in order at 1:30PM.

NPCC Antitrust Compliance Guidelines
Ruida Shu announced that this meeting is under the requirements of NPCC Antitrust Compliance Guidelines.

Agenda Items:

1. **Respond to comments**

2. **Review of PRC-006-NPCC-01 Draft Redline**

   Action Item:
   Rationale Box for Inhibit Threshold written by Dean Latulipe and Dan Taft will add some additional language.
   An inhibit function provides supervisory control over a UFLS relay. For example, an undervoltage inhibit feature prevents UFLS relay operation if the sensed voltage

decreases below an adjustable setting. An undervoltage inhibit function is intended to prevent operation of a UFLS relay when the transmission supply is lost to distribution station feeding many induction motors. Following loss of the transmission supply, motors may support the voltage while the motors coast down in speed. The motors coasting down (ringing down) will look like an Underfrequency event to the relay. The inhibit setting is set to a voltage above which the motor load is expected to sustain. This prevents the Underfrequency relay from tripping and locking out distribution feeder breakers supplying the motor load, between the time the transmission supply line trips and the time when the line recloses to restore the load. Voltages sustained by motors that are coasting down (e.g. 0.70 pu) are typically much lower than voltages at which the UFLS relays are required to operate to meet UFLS performance criteria. However, motor loads supplied by cable networks typically have higher ring down voltages because of cable charging. Therefore, care must be taken so that the voltage inhibit setting is not higher than the voltage at which UFLS relays are required to operate to meet UFLS performance criteria

Action Item:
Dean Latulipe will copy and paste his new updated graph into the redline document**.**

Action Item:
Dean Latulipe will draft a response for OPG comment Question #1.

Action Item:
Completed by Dean Latulipe on R4 language.
The drafting team does not know what is being referred to "outages" R4. This language is a carry-over from the existing standard. The drafting team sees no need to keep this "outage" reference in R4. Therefore, the drafting team proposes that this reference to outages should be stricken from R4 as follows:
R4. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall implement an automatic UFLS program, ~~reflecting normal operating conditions, excluding outages~~. ~~The automatic UFLS program shall~~ on an island basis for each island identified per the NERC PRC Standard on UFLS. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

Action Item:
Guy Zito will investigate materiality clause for R3 and discuss internally with in NPCC which is comment C in PSEG comment question 1.

Action Item:
Vincent Morrissette will draft a response for question 1 section (d) on PSEG comments.

Action Item:
Brian Robinson will draft a response to IESO comment question #1.

Action Item:
Jeannette Gauthier will draft a response for OPG comment question #3.

Action Item:
Ruida Shu and Guy Zito will check with Daniel Kidney in terms of registration issues regarding DP UFLS only entities.

Action Item:
Dean Latulipe will draft a response for OPG question #5, #6 and #7.

Dan Taft adjourned the meeting at 4:25PM.

3. **Next Steps**
   The next scheduled conference call is November 20, 2017 from 1:30PM-4PM.

Northeast Power Coordinating Council, Inc. (NPCC)

Antitrust Compliance Guidelines

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

It is the responsibility of every NPCC participant and employee who may in any way affect NPCC's compliance with the antitrust laws to carry out this commitment.

Participants in NPCC activities (including those participating in its committees, task forces and subgroups) should refrain from discussing the following throughout any meeting or during any breaks (including NPCC meetings, conference calls and informal discussions):

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

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

Any NPCC meeting participant or employee who is uncertain about the legal ramifications of a particular course of conduct or who has doubts or concerns about whether NPCC's antitrust compliance policy is implicated in any situation should call NPCC's Secretary, Ruta Skučas, Esq. at 1-202-470-6428.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**)**	**Docket No. RM18-1-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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Exhibit A – Testimony of Gerry W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation
"Powering America: Defining Reliability in a Transforming Electricity Industry"

Exhibit B – Synopsis of NERC Reliability Assessments
The Changing Resource Mix and the Impacts of Conventional Generation Retirements

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Grid Reliability and Resilience Pricing	**)**	**Docket No. RM18-1-000**

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

On September 28, 2017, the Department of Energy ("DOE") proposed a Grid Resilience Pricing Rule ("Proposed Rule") for action by the Federal Energy Regulatory Commission (the "Commission").[1] On October 4, 2017, the Commission requested comments on several questions related to the Proposed Rule ("Request for Comments").[2] The North American Electric Reliability Corporation ("NERC")[3] hereby provides comments on the Proposed Rule and the Commission's Request for Comments.

Consistent with its core mission, NERC conducts regular and special assessments of the Bulk Power System ("BPS"), including assessments of the changing generation resource mix. NERC assessments find that the BPS continues to operate reliably, while identifying potential risks related to the changing resource mix. These comments reflect NERC's key findings and recommendations related to secure capacity and essential reliability services. As discussed below, NERC recommends that the Commission continue to pursue policy reform that recognizes the secure capacity and essential reliability service attributes currently and

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1 *Grid Reliability and Resilience Pricing*, Notice Inviting Comments, Docket No. RM18-1-000 (Oct. 2, 2017) (unpublished letter order) (proposing a new rulemaking under 42 U.S.C. § 7173 (2012)).

2 *Grid Reliability and Resilience Pricing*, Docket No. RM18-1-000 (Oct. 4, 2017) (unpublished letter order).

3 The Federal Energy Regulatory Commission certified NERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act, in its order issued on July 20, 2006, in Docket No. RR06-1-000. *See Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006), *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 342 (D.C. Cir. 2009).

historically provided by coal and nuclear generation, incentivizes development of such reliability attributes in non-synchronous resources, such as wind and solar facilities, and promotes fuel assurance for natural gas-fired resources.

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Notices and communications with respect to these comments may be addressed to the following:[4]

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II. EXECUTIVE SUMMARY

Reliable and resilient operation of the BPS requires a balanced portfolio of diverse generation resources that provide adequate capacity and essential reliability services to meet consumer needs and support the system. The right combination and amount of resources and transmission together maintain adequacy of the system. The changing resource mix is altering this combination, influencing the operational characteristics of the grid and challenging reliable system planning and operation. The attached *Synopsis of NERC Reliability Assessments, The*

[4] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2017), to allow the inclusion of more than two persons on the service list in this proceeding.

Changing Resource Mix and the Impacts of Conventional Generation Retirements ("Synopsis of NERC Reliability Assessments") (Exhibit B) describes how resource diversity improves resilience. [5] The reliability benefits provided by resource diversity can be even greater when policies and market rules recognize the value provided by essential reliability services and support greater fuel assurance by encouraging firm transportation, multiple pipeline connections, and dual-fuel capability. Recognizing the reliability benefits provided by all generation should help ensure that the generation resource mix continues to evolve in a manner that avoids creating risk to reliability of the BPS.

As the Electric Reliability Organization, NERC must "conduct periodic assessments of the reliability and adequacy of the bulk-power system in North America."[6] To fulfill this responsibility, NERC annually assesses seasonal and long-term reliability of the BPS and conducts special assessments regarding developing issues – such as the changing resource mix. As summarized in the Synopsis of NERC Reliability Assessments, NERC's assessments have identified and analyzed the manner in which the generation resource mix has been evolving from a fleet that primarily relies on coal and nuclear generation to one with increasing levels of non-synchronous and natural gas-fired resources.[7] With their benefits, non-synchronous resources also experience variability, while natural gas-fired resources are more susceptible to fuel interruptions in the supply chain than coal and nuclear generation. In the Commission's recent

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[5] *Synopsis of NERC Reliability Assessments, The Changing Resource Mix and the Impacts of Conventional Generation Retirements*, at p. 4 (May 9, 2017) (attached hereto as Exhibit B). *See also*, Testimony of Gerry W. Cauley, President and Chief Executive Officer, North American Electric Reliability Corporation, "*Powering America: Defining Reliability in a Transforming Electricity Industry,"* Before the Subcommittee on Energy Committee on Energy and Commerce, U.S. House of Representatives, at p. 4 (Sept. 14, 2017) (stating, "Variable resources significantly diversify the generation portfolio and can contribute to reliability and resilience in important ways.") (attached hereto as Exhibit A).

[6] 16 U.S.C. §824o(g).

[7] NERC, *Essential Reliability Services Task Force Measures Report*, (November 2015), http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Framework%20Report%20-%20Final.pdf ("ERSTF Report").

notice of proposed rulemaking to require that newly interconnecting resources be capable of providing primary frequency response, the Commission reported:

> [T]he nation's resource mix has undergone significant change …. This transformation has been characterized by the retirement of baseload, synchronous generating facilities and the integration of more distributed generation, demand response, and natural gas generating facilities, and the rapid expansion of non-synchronous variable energy resources (VERs) …. the U.S. Energy Information Administration (EIA) has observed that the U.S. added approximately 13 gigawatts (GW) of wind, 6.2 GW of utility scale solar photovoltaic (PV), and 3.6 GW of distributed solar PV generating facilities in 2014 and 2015. Conversely, NERC has reported that almost 42 GW of synchronous generating facilities (e.g., coal, nuclear, and natural gas) have retired between 2011 and 2014, and the EIA recently reported that nearly 14 GW of coal and 3 GW of natural gas generating facilities retired in 2015.[8]

NERC's forthcoming *2017 Long Term Reliability Assessment* will also note that six nuclear units have retired since 2012, with 10.5 GW of additional capacity from 14 units at seven plants planning to retire by 2025. Retirement of traditional coal and nuclear generation with rapid replacement by non-synchronous and natural gas-fired generation is introducing new considerations for reliability and resilience planning.

Coal and nuclear generation serve a critical reliability function within the diverse resource mix by providing secure capacity to serve firm load and supporting reliability and resilience of the BPS. Specifically, coal and nuclear generation are secure sources of dependable capacity in support of resource adequacy (*see infra*, Section III.A) and substantial amounts of essential reliability services in the form of inertia and voltage support (*see infra*, Section III.B), with low levels of unavailability due to fuel supply constraints (*see infra*, Section III.C). These reliability attributes balance the intermittency of non-synchronous resources and potential fuel interruptions of natural gas-fired resources. As reflected in Mr. Gerry Cauley's, President and

[8] *Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response*, Notice of Proposed Rulemaking, 157 FERC ¶ 61,122, P 12 (2016) (currently pending for Commission approval) (internal citations omitted).

Chief Executive Officer of NERC, Testimony, "[w]ith appropriate insight, careful planning, and support, the electricity sector can continue to navigate these changes in a manner that results in enhanced reliability and resilience. Even with all the changes underway, the bulk power system (BPS) remains highly reliable and resilient, showing improved reliable performance year over year."[9]

NERC is continuing to study the reliability implications of coal and nuclear generation retirements and the changing resource mix. While NERC has not identified an immediate or near-term emergency related to such retirements, NERC assessments demonstrate that the ongoing trend reduces system flexibility to respond to events and may affect reliability, increasing risk to the BPS. NERC appreciates the Commission's attention to NERC's findings on how the changing resource mix may affect reliability. It is critical that policy makers understand and address how the ongoing evolution of the North American generation fleet influences reliability. NERC recommends that the DOE and Commission continue to pursue policies and market rules supporting reliability and resilience.

III. COMMENTS

The North American BPS is reliable and resilient.[10] In NERC's State of Reliability 2017, NERC highlighted, "the BPS provided an adequate level of reliability (ALR) during 2016."[11] Reliability is a function of resource adequacy and operating reliability. Resource adequacy reflects the ability of the system to supply electricity to meet consumer demand.[12] Operating reliability includes resilience and is the ability of the system to withstand sudden disturbances to

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9 Exhibit A, at Summary.

10 *Id.* at p. 1.

11 *See*, NERC, *State of Reliability 2017*, at p. 5 (June 2017), *available at*, http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/SOR_2017_MASTER_20170613.pdf.

12 Exhibit B, at p. 1 (stating, "NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects.").

system stability or unanticipated loss of components.[13] A balanced portfolio of generation resources and transmission infrastructure ensures that the system has adequate capacity to meet consumer needs and is ready to respond to unexpected outages or extreme weather events.[14]

Coal and nuclear generation support reliability by providing dependable capacity, substantial essential reliability services in the form of inertia and voltage control, and fuel security. These reliability attributes balance the variable characteristics of non-synchronous variable energy resources and the fuel sensitivity of both non-synchronous and natural gas-fired resources.[15] Non-synchronous and natural gas-fired resources also present reliability benefits, such as resource diversity, capacity, and the essential reliability services they can provide. Together, these resources support reliable and resilient operation of the BPS. The Commission should continue to pursue policies that recognize the reliability attributes of all resources and find opportunities to enhance these attributes as discussed herein.

A. Reliable operation of the BPS requires dependable capacity.

Reliable operation of the BPS requires dependable capacity on a consistent basis to address consumer needs, the impacts of extreme weather conditions, and sudden disturbances on the system. Without dependable resource adequacy, a Balancing Authority responsible for managing the balance of demand and resources may become capacity deficient and unable to serve firm load, which in turn, may lead to manual load shedding. Coal and nuclear generation

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[13] *Id.* The National Infrastructure Advisory Council defines "resilience" as follows: "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event." This definition is cited in, NERC, *Severe Impact Resilience: Considerations and Recommendations* (May 9, 2012), *available at* http://www.nerc.com/docs/oc/sirtf/SIRTF_Final_May_9_2012-Board_Accepted.pdf.

[14] Exhibit B, at p. 1.

[15] *Id*. at pp. 3-4 (describing the reliability attributes of coal and nuclear generation and the benefits of a diverse resource portfolio).

generally have the unique attributes of low outage rates, high availability rates, and, with on-site storage, low fuel supply sensitivity necessary to provide secure and stable capacity to the grid.[16]

While their current benefits and potential are significant, non-synchronous generation and natural gas-fired facilities do not currently replace the secure capacity provided by coal and nuclear generation. Recognizing the need for sufficient capacity, the Commission has approved market mechanisms compensating certain generators for reliability purposes.[17] For example, the Commission permitted the Midcontinent Independent System Operator, Inc. ("MISO") to designate coal-fired or other facilities planned for retirement as "System Support Resources" ("SSR") if all or a portion of the resource's capacity is necessary for reliability.[18] The Commission has stated that it expects entities will use "[a]greements [designating resources as SSR units] only as a last-resort measure to meet short-term reliability needs precipitated by the retirement or suspension of a resource and will ensure that SSR Agreements have a limited and short duration."[19] While this policy is limited, it is appropriate for the Commission to consider the reliability attributes provided by coal and nuclear generation to ensure that the generation resource mix continues evolving in a manner that maintains a reliable and resilient BPS.

B. Reliable operation of the BPS requires essential reliability services.

Essential reliability services are vital to reliable operation of the BPS. Power system operators use these essential reliability services, such as frequency response, voltage control, and

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16 *Id.* at p. 2.

17 *PJM Interconnection, L.L.C.*, 107 FERC ¶ 61,112, at P 8 (2004); *Calif. Indep. Sys. Operator Corp.*, 138 FERC ¶ 61,112 (2012); *Calif. Indep. Sys. Operator Corp.*, 134 FERC ¶ 61,211 (2011); *ISO New England, Inc.* 125 FERC 61,102, *order on clarification*, 125 FERC ¶ 61,234 (2008), *order denying reh'g*, 130 FERC ¶ 61,089 (2010); *and Midwest Independent Transmission System Operator, Inc.*, 140 FERC ¶ 61,237 (2012).

18 *See e.g., Midwest Independent Transmission System Operator, Inc.*, 140 FERC ¶ 61,237 (2012); *and AmerenEnergy Resources Generating Company*, 153 FERC ¶ 61,062 (2015) (permitting SSR designation for a 90 MW coal facility).

19 *Midwest Independent Transmission System Operator, Inc.*, 140 FERC ¶ 61,237, P 12 (2012).

ramping, to plan and operate the BPS reliably under a variety of system conditions. Coal and nuclear generation provide substantial essential reliability services as a function of large spinning generators and governor control settings, along with reactive support for voltage control.[20]

As the generation resource mix evolves, reliability depends on the capacity that resources provide, their operating characteristics, and their capability to provide essential reliability services. When operating, variable energy resources (which are not synchronously connected to the grid through inverters) can provide essential reliability services, although costs and market rules may not fully recognize such capabilities.[21] Natural gas-fired resources provide essential reliability services and often support frequency response needs, however, natural gas-fired generation, like non-synchronous variable energy resources, receives fuel on a "just-in-time" basis, and is sensitive to fuel supply availability.

NERC supports continued Commission action to ensure that newly interconnecting generation resources provide essential reliability services. After NERC began highlighting the potential challenges that might arise from the changing resource mix, the Commission initiated rulemakings to require that new resources be capable of providing essential reliability services. First, the Commission revised its *Pro Forma* Interconnection Agreements to require that all

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[20] Exhibit B, at p. 2. *See also.* ERSTF Report, at p. iv (stating, "Conventional units such as coal plants provide frequency support services as a function of their large spinning generators and governor control settings along with reactive support for voltage control. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available."); *and* NERC, *Essential Reliability Services Task Force A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability*, at p. 8 (October 2014), *available at*, http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf.

[21] ERSTF Report, at p. iv (adding, "Gas-fired units, VERs, storage, and other resources are equipped to provide similar reliability services; however, the functionality may not always be installed or made available due to costs or market rules. The controllability of new generator and load resources to maintain the balance between load and generation, especially during ramping periods, is necessary to ensure reliability).

newly interconnecting generators ride through abnormal frequency and voltage events and not disconnect during such events. In directing these revisions, the Commission acknowledged that:

> [A]s the North American Electric Reliability Corporation (NERC) has noted in multiple reports, the mix of generation resources is changing and the high penetration of distributed energy resources will impact the reliability of the electric grid if sufficient care is not taken to mitigate potential adverse impacts. NERC also has found that a lack of coordination between small generating facilities and Reliability Standards can lead to events where system load imbalance may increase during frequency excursions or voltage deviations due to the disconnection of distributed energy resources, which may exacerbate a disturbance on the Bulk-Power System….[22]

Second, in 2016, the Commission began a rulemaking proposing to revise the *Pro Forma* Interconnection Agreements to require that all newly interconnecting resources be capable of providing primary frequency response service.[23] All new resources should be capable of providing essential reliability services.[24] NERC encourages further policies that would acknowledge the value provided by essential reliability services and require the integration of new resources in a manner that supports a reliable and resilient electric grid.

C. Reliable operation of the BPS requires a generation resource mix that includes resources with fuel assurance and low sensitivity to disruptions of the fuel supply.

Reliable operation of the BPS requires that the generation resource mix include facilities that have fuel assurance and low sensitivity to fuel supply disruptions. A fuel diverse generation portfolio creates redundancies in available resources and supports fuel assurance. Fuel diversity also results in an electric grid that is less susceptible to disturbances and better capable of

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[22] *Requirements for Frequency and Voltage Ride Through Capability of Small Generating Facilities*, Order No. 828, 156 FERC ¶ 61,062, P 8 (2016).

[23] *Supra*, n. 8.

[24] *See e.g.*, ERSTF Report, at p. vi (stating, "All new resources should have the capability to support voltage and frequency"); *and Supplemental Comments of NERC in Response to Notice of Request for Supplemental Comments*, Docket No. RM16-6-000, at p. 2 (filed Oct. 10, 2017) (reiterating, "All newly interconnecting resources should fall within the scope of the Commission's proposed primary frequency response requirements – including storage.").

restoring service quickly after an event on the system. Without fuel assurance, external events such as hurricanes, polar vortices, and natural gas and pipeline disruptions may have a greater and longer impact on available capacity. Coal and nuclear generation serve a key function in this regard, as these facilities typically maintain onsite fuel and can therefore generally operate with greater independence from the fuel supply chain.[25] Natural gas-fired generation with dual-fuel capabilities can also operate resiliently after natural gas fuel supply disruptions.

Burgeoning reliance on natural gas-fired generation as a replacement for coal and nuclear generation decreases fuel diversity and increases single source fuel dependency. While natural gas-fired resources serve a key function in the generation fleet, single source fuel dependency can have adverse impacts under common-mode outages. Natural gas-fired generation faces greater susceptibility to fuel supply chain disruption than coal and nuclear generation, because it typically relies upon "just-in-time" fuel transportation and delivery. A large portion of fuel supplied to natural gas generation units is transported under interruptible pipeline contracts. Moreover, natural gas supply is subject to curtailment during force majeure events affecting the fuel supply chain.[26] Natural gas fuel dependency is particularly concerning in areas where: (i) generators rely on interruptible gas pipeline transportation; (ii) natural gas interstate pipelines are constrained to meet demand beyond what has been contracted and committed; and (iii) there is

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[25] NERC, *2014–2015 Winter Reliability Assessment*, at pp. 3-4 (November 2014), *available at*, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2014WRA_final.pdf; NERC, *2013 Special Reliability Assessment: Accommodating an Increased Dependence on Natural Gas for Electric Power*, *available at*, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf (May 2013). Coal is not immune from fuel supply issues. For example, during the 2014 polar vortex, frozen coal stockpiles had a negative impact on generator availability and that rail congesting was impeding coal producers from replenishing power plant stockpiles. *See, 2014-2015 Winter Assessment*, at p. 5 (November 2014).

[26] *Id.* at pp. 3-4 (summarizing, "the reliability ramifications of a substantial reliance on just-in-time fuel delivery and the potential for single points of failure and common-mode outages across natural gas infrastructure must be taken into account when considering resource adequacy assessments.").

greater reliance on natural gas-fired generation as a "primary" generation resource.[27] Natural gas-fired generation is also sensitive to market signals. Higher natural gas prices or regulation that curtails hydraulic fracturing could affect economic considerations currently making natural gas-fired generation a cost effective alternative to coal and nuclear generation. As highlighted in NERC's 2014/2015 Winter Reliability Assessment, "increased reliance on gas-fired generation requires new approaches for assessing reliability."[28]

Recent events demonstrate the risks created by single source fuel dependency. For example, during the 2013 and 2014 winter season, the ISO-New England region lost more than 8,000 MW of gas-fired generation during its peak hour. Lack of fuel, stemming from non-Firm fuel delivery arrangements, forced a majority of these generators out of service.[29] The Aliso Canyon incident provides further illustration, as this outage of a single underground gas storage facility in Southern California affects fuel supply to approximately 9,800 MW of generation at 18 power plants.[30] The facility also supports ramping requirements to accommodate the variability of renewable energy resources. While being monitored, the continuing outages at Aliso Canyon have the potential to disrupt reliability in Southern California until the facility is fully operational or other measures mitigate the situation. As summarized in NERC's *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, "[t]he electric sector's growing reliance on natural gas raises concerns regarding the ability to maintain BPS reliability when facing constraints on the natural gas

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27 *Id.*

28 *Id.* at p. 8.

29 *Id.* at p. 4, fig. 3.

30 *See*, NERC, *Short-Term Special Assessment: Operational Risk Assessment with High Penetration of Natural Gas-Fired Generation*, at pp. 10-11 (May 2016), *available at*, http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20Short-Term%20Special%20Assessment%20Gas%20Electric_Final.pdf.

delivery systems."[31] Later this fall, NERC plans to release additional analysis of the potential impacts to reliability from a large disruption on the natural gas system.

The Commission should consider policies that build upon its prior examination of electric – natural gas coordination to better calibrate the electric and gas industries and to help ensure fuel adequacy during both average and extreme conditions challenging fuel supply.[32] These measures can begin to mitigate some of the risks created by single source fuel dependency. For example, the Commission could encourage firm transportation, multiple pipeline connections, and dual-fuel capability as these measures can reduce the risks from common-mode failures and wider-spread reliability challenges from fuel supply disruptions. Further, the Commission should consider requiring that resource adequacy assessments account for reliability ramifications associated with the "just-in-time" natural gas fuel delivery model. Finally, the Commission should consider whether it would be beneficial to pursue market rules that would provide assurances that generators will perform in normal and extreme circumstances.

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[31] *Id.* at p. 12.

[32] *See e.g., Request for Comments of Commissioner Moeller on Coordination between the Natural Gas and Electricity Markets*, Docket No. AD12-12-000 (Feb. 3, 2012).

IV. CONCLUSION

Wherefore, for the reasons stated above NERC supports DOE and Commission efforts to recognize the reliability attributes provided by coal and nuclear generation and incentivize the development of such reliability attributes by other generation resources. Continued policy and market reform should maintain the existence of a balanced generation portfolio supporting a reliable and resilient electric grid.

Respectfully submitted,

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Date: October 23, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket No. RM18-1-000.

Dated at Washington, DC this 23rd day of October, 2017.

/s/ Courtney M. Baughan

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Exhibit A

Testimony of Gerry W. Cauley
President and Chief Executive Officer of the
North American Electric Reliability Corporation
"Powering America: Defining Reliability in a Transforming Electricity Industry"

"Powering America: Defining Reliability in a Transforming Electricity Industry"

September 14, 2017

Before the Subcommittee on Energy
House Committee on Energy and Commerce
U.S. House of Representatives
Washington, DC

Testimony of Gerry W. Cauley
President and Chief Executive Officer
North American Electric Reliability Corporation

SUMMARY

The electricity sector is undergoing significant change that is unprecedented for both its transformational nature and rapid pace, presenting new challenges and opportunities for reliability. With appropriate insight, careful planning, and support, the electricity sector can continue to navigate these changes in a manner that results in enhanced reliability and resilience. Even with all the changes underway, the bulk power system (BPS) remains highly reliable and resilient, showing improved reliable performance year over year.

About NERC and NERC's Role in Evaluating BPS Reliability and Security

The North American Electric Reliability Corporation (NERC) is a private non-profit corporation certified by the Federal Energy Regulatory Commission (FERC) as the Electric Reliability Organization (ERO) for the United States. NERC reliability assessments evaluate the performance of the BPS, identify reliability trends, anticipate challenges, and provide a technical platform for important policy discussions. NERC's analyses of system disturbances also provide critical insights.

Reliability and How the Changing Resource Mix Affects It

Adequate capacity must be maintained to serve firm load. It is important to understand and plan for the different operating characteristics of variable resources. These resources also contribute to reliability and resilience.

Changes occurring in the generation resource mix and new technologies are altering the operational characteristics of the grid and will challenge system planners and operators. Conventional baseload generation has important reliability attributes. Reliability of the electric grid depends upon the operating characteristics of replacement resources.

Learning from System Events – A Case Study

NERC's analysis of a frequency excursion event in California revealed that protection settings on certain solar facility inverters caused erroneous tripping. This led to a recommendation to adjust the inverter settings. It is an example of NERC's focus on identifying small, isolated events that could pose greater threats to reliability.

DOE Staff Report

The Department of Energy's (DOE) recent staff report cites NERC's assessments. Many topics, findings, and recommendations in the staff report are consistent with NERC's work.

The Changing Resource Mix: NERC Recommendations

Baseload Retirements – Regulators and market operators should keep in mind the changing reliability aspects of the grid when considering resource needs, adequacy requirements, distribution-level interconnection requirements, and long-term resiliency.

Essential Reliability Services – All new resources should have the capability to support voltage and frequency. Policies and market mechanisms may not provide enough incentive or clarity.

Natural Gas Regulation and Markets – Regulators and policy makers should evaluate the natural gas regulatory framework for transportation priority and construction. Market operators should also evaluate whether market rules should be revised to provide assurances that generators will perform in normal and extreme circumstances.

Introduction

Good morning Chairman Upton, Ranking Member Rush, members of the subcommittee and fellow panelists. I am Gerry Cauley, President and Chief Executive Officer of NERC. On behalf of NERC, I appreciate the committee's focus on reliability in a transitioning electricity industry.

The electricity sector is undergoing significant change that is unprecedented for both its transformational nature and rapid pace. Such extraordinary change presents new challenges and opportunities for reliability. Dramatic advances in technology, customer preferences, public policy, and market forces are altering the generation resource mix and challenging the conventional understanding of baseload power, traditionally provided by large generating units with low maintenance and forced outage rates. These changes also are pressuring regulatory policy, sometimes blurring the lines between federal and state jurisdiction. Within the North American continent, cross-border electricity trade between the United States, Canada, and Mexico requires enhanced cooperation. Security is yet another major challenge as the threat landscape becomes ever more complicated with the rise of malicious actors seeking to attack critical infrastructure through cyber warfare.

With appropriate insight, careful planning, and support, I am confident the electricity sector will continue to navigate these changes in a manner that results in enhanced reliability and resilience.[1] Even with all the changes underway, the BPS remains highly reliable and resilient, showing improved reliable performance year over year.[2] This record demonstrates the strong commitment to reliability by industry and all stakeholders, and the effectiveness of the model adopted by this committee in the Energy Policy Act of 2005.

[1] The National Infrastructure Advisory Council provides this definition of "resilience" – "Infrastructure resilience is the ability to reduce the magnitude and/or duration of disruptive events. The effectiveness of a resilient infrastructure or enterprise depends upon its ability to anticipate, absorb, adapt to, and/or rapidly recover from a potentially disruptive event." This definition is cited in a NERC report, "Severe Impact Resilience: Considerations and Recommendations" (May 9, 2012).

[2] *See* "State of Reliability 2017" (NERC, June 2017).

While these accomplishments are highly significant, I have learned from more than 35 years of experience that reliability requires constant vigilance. This is more true now than at any point in history. Working with FERC, DOE, industry, and numerous other stakeholders, NERC remains focused on identifying, assessing, and responding to reliability risks posed by change in the electricity sector. I am pleased to discuss NERC's work to address this critical priority.

About NERC and NERC's Role in Evaluating BPS Reliability and Security

NERC is a private non-profit corporation that was founded in 1968 to develop voluntary operating and planning standards for the users, owners and operators of the North American BPS. Pursuant to Section 215 of the Federal Power Act (FPA) (16 U.S.C. §824o) and the criteria included in Order No. 672 for designating an ERO, FERC certified NERC as the ERO for the United States on July 20, 2006. On March 16, 2007, FERC issued Order No. 693 which approved the initial set of reliability and security standards. These reliability standards became mandatory in the United States on June 18, 2007.

NERC develops and enforces reliability and security standards; annually assesses seasonal and long-term reliability; monitors the BPS through system awareness; and educates, trains, and certifies industry personnel. NERC performs a critical role in real-time situational awareness and information sharing to protect the electricity industry's critical infrastructure against threats to the BPS. NERC's responsibility spans the continental United States, Canada, and Mexico. Our jurisdiction includes users, owners, and operators of the BPS, which serves more than 334 million people.

Section 215(g) of the FPA requires NERC to assess the reliability and adequacy of the BPS. NERC reliability assessments evaluate the performance of the BPS, identify reliability trends, anticipate challenges, and provide a technical platform for important policy discussions. Each year, NERC assesses the overall reliability, adequacy, and associated risks that could impact the upcoming summer and winter seasons, and the long-term, 10-year period. As emerging risks and potential impacts to reliability are identified, NERC also conducts special assessments on focused reliability topics that provide a similar technical framework and insights.

By identifying and quantifying emerging reliability and security issues, we are able to provide risk-informed recommendations and support a learning environment for industry to pursue improved reliability performance. These recommendations, along with the associated technical analysis, provide the basis for actionable enhancements to resource and transmission planning methods, planning and operating guidelines, security, as well as NERC reliability and security standards. In short, NERC's objective assessments provide critical insights necessary for assuring reliability and security of a rapidly changing electricity sector.

Reliability and How the Changing Resource Mix Affects It

The North American BPS is designed to be highly reliable, robust, and resilient. The system is interconnected, and the integrated networks work together to maintain reliability through both wide-area interregional planning and coordinated system operations. The adequacy of the system is maintained by having the right combination and amount of resources and transmission to deal with unexpected facility outages or extreme weather events. Operating reliability is maintained in real-time through highly coordinated operator actions across many operating companies.[3] The system is also planned as many as 15 years in advance through highly detailed, complex, and data-intensive power system simulations.

The BPS resource mix is changing in fundamental ways. As some conventional baseload generation from coal and nuclear retires, variable energy resources – especially wind and solar – are rapidly expanding and capturing the majority share of new capacity additions. The balancing resource tends to be natural gas. It is essential to understand the implications of these trends in order to maintain reliability.

The changing resource mix can fundamentally impact reliability in two major ways:

[3] NERC defines "reliable operation" in the following manner: "Operating the elements of the [Bulk-Power System] within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements. *See* "Glossary of Terms Used in NERC Reliability Standards."

- Resource Adequacy – A balancing authority responsible for managing the balance of demand and resources through unit commitment and forecasting must maintain sufficient capacity at all times to serve firm load.

- Planning for Variable Resources – It is important to understand and plan for the different operating characteristics of variable resources. These include planning for adequate essential reliability services, managing faster fault-clearing times, reduced oscillation dampening, and unexpected inverter action. Variable resources significantly diversify the generation portfolio and can contribute to reliability and resilience in important ways.

The rapid changes occurring in the generation resource mix and new technologies are altering the operational characteristics of the grid and will challenge system planners and operators. More specifically:

- Impact of Retirements – Conventional baseload electric generating units, such as coal and nuclear plants, provide frequency support services as a function of their large spinning generators and governor-control settings along with reactive support for voltage control. Power system operators use these services to plan and operate reliably under a variety of system conditions. These units also have relatively high availability rates and on-site fuel.

- Replacement Resource Capability and Characteristics – As the generation resource mix evolves, the reliability of the electric grid depends upon the operating characteristics of the replacement resources. Natural gas-fired units, variable generation, storage, and other resources can provide reliability services. However, as a practical matter, operating characteristics, economics, and market rules can affect whether these resources are equipped and available to provide reliability services. New generator and load resources must maintain the balance between load and generation, especially during ramping periods. In addition, in some areas, substantial amounts of generation is now being added "behind the meter" (e.g., rooftop solar). It will become increasingly important for system operators to have visibility into these resources.

Learning from System Events – A Case Study

NERC also gains considerable insight into reliability risk through analysis of system disturbances. An event last year in California is a recent example that is directly related to avoiding risk from the changing resource mix. It shows how NERC identifies and addresses a small problem today in order to avoid a potentially larger, more significant problem in the future.

On August 16, 2016, smoke from the Blue Cut wildfire in San Luis Obispo County, California, resulted in the tripping of two 500 kV lines in the active fire area. There was a noticeable frequency excursion with Peak Reliability reporting the loss of more than 1,000 MW across multiple renewable resources following these line outages. California ISO, Southern California Edison, and Peak Reliability confirmed that no conventional generators tripped, and that the near instantaneous loss of resources were all utility-scale renewables, primarily solar.

While the event did not rise to the level of a major disturbance by NERC criteria, the occurrence was significant and unusual because it is the first known major loss of renewable resources due to a transmission system disturbance. Subsequent analysis of this event determined that the protection settings on the solar facility inverters caused erroneous tripping. In response, manufacturers of inverters that experienced this type of tripping during the event have recommended a change in their inverter settings to avoid this issue. This recommendation calls for the addition of a time delay to their frequency tripping settings. This will allow the inverter to "ride through" the transient/distorted waveform period without tripping.

NERC has taken two additional actions in response to the Blue Cut wildfire event. In June, we published a report prepared by a joint task force of NERC, the Western Electricity Coordinating Council, FERC, and involved entities to analyze this disturbance, determine the causes, and develop key findings and recommendations.[4] We also issued a public Level II NERC Alert to industry. This alert – which requires a response – provides specific actions that NERC registered entities should consider taking to address this particular issue. NERC's work following this event is an example of detecting "faint signals" – identifying small, isolated events that could pose greater threats to reliability.

DOE Staff Report

DOE's recent study, "Staff Report to the Secretary on Electricity Markets and Reliability," cites NERC's assessments throughout the reliability and resilience chapter. We appreciate DOE's focus on reliability and resiliency as well as recognition of NERC's long time work on these issues. Many topics, findings, and recommendations in the staff report are consistent with NERC's work.

[4] *See* "1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report" (NERC, June 2017).

Specifically, as conventional resources retire, essential reliability services much be maintained. Voltage control, frequency support and ramping capability must be provided based on the configuration and needs of the system. Reliable operation of the grid depends upon these characteristics.

As an enhanced yardstick of reliability, resilience is reflected throughout NERC's programs. For instance, NERC's definition of "adequate level of reliability" includes a performance outcome providing for expeditious recovery from major system disturbances. NERC has a family of emergency preparedness and operations standards covering such topics as blackstart capability, system restoration coordination, and geomagnetic disturbance operations.[5] NERC published a report on severe impact resilience[6] and has collaborated with FERC and regional entities on industry's response and recovery plans.[7]

The combination of growth in natural gas demand within the electricity sector and its changing status among the gas-consuming sectors continues to increase significantly the interdependencies between the natural gas and electricity industries. Real-time delivery of natural gas through a network of pipelines and bulk gas storage is critical to support electric generators. It is also important to evaluate the impacts of a loss of major pipeline infrastructure. NERC has examined natural gas and electricity interdependencies in detail and has developed recommendations for the power industry.[8]

DOE's staff report also recommends expanded cooperation on grid reliability with Canada and Mexico. Cross-border interconnections require shared priorities for reliability and security throughout North America. Consistent with a set of principles signed in 2005 by DOE and Canadian provincial and federal counterparts, NERC is structured as an international organization. Under memoranda of understanding or other agreements with authorities in each province, NERC standards are adopted and enforced under provincial laws. In addition to strong

[5] *See* Emergency Preparedness and Operations Standards.
[6] *See* "Severe Impact Resilience: Considerations and Recommendations" (NERC, 2012).
[7] *See* "FERC-NERC-Regional Entity Joint Review of Restoration and Recovery Plans" (2016) and "Further Joint Study Report: Planning Restoration Absent SCADA or EMS" (2017).
[8] *See "*Accommodating an Increased Dependence on Natural Gas for Electric Power*"* (NERC, 2013).

collaboration with Canadian provincial and federal government stakeholders, NERC works extensively with Canadian industry on reliability and security matters, and has partnered with DOE on numerous relevant efforts. In March, NERC signed a memorandum of understanding (MOU) with government authorities in Mexico to advance shared reliability priorities as Mexico implements comprehensive electricity reforms. NERC expects that Mexico will become a full participant, on par with the United States and Canada, as the implementation of the MOU is fully realized over the next several years.

The Changing Resource Mix: NERC Recommendations

As detailed above, NERC continually assesses the reliability of the BPS to evaluate system performance, identify trends, assist policymakers, and promote a learning environment. NERC's event analysis group also supports these objectives through detailed examination of system disturbances. Based upon this recent work, NERC has formulated recommendations related to the changing resource mix. For additional findings and recommendations, the appendix includes references to recent NERC assessments.

Baseload Retirements – State regulators and market operators should keep in mind the changing reliability aspects of the grid when considering resource needs, adequacy requirements, distribution-level interconnection requirements, and long-term resiliency. States and FERC should continue review of the economic and policy issues impacting fuel secure baseload generation in order to plan for and identify reliability implications of these retirements. States and FERC should ensure that required reliability characteristics are considered when identifying future reliability and capacity needs.

Essential Reliability Services – All new resources should have the capability to support voltage and frequency. Some variable energy resources and storage technologies can contribute to essential reliability services. Policies and market mechanisms may not provide enough incentive or clarity to ensure these services are maintained across the system. Regional transmission organizations and independent system operators and FERC have taken steps in this direction, which should continue.

Natural Gas Regulation and Markets – Regulators and policy makers should evaluate whether the natural gas regulatory framework for transportation priority and construction is compatible with the requirements of the changing BPS. Market operators should also evaluate whether market rules should be revised to provide assurances that generators will perform in normal and extreme circumstances.

Conclusion

The transitioning electricity sector poses challenges and opportunities for reliability. Retirements of baseload generation and the addition of greater variable resources are altering the operating characteristics of the grid. A significant influx of natural gas generation raises unique considerations for fuel delivery and dependence. To address the challenges and capitalize upon the benefits of a more diverse resource mix, industry stakeholders and policymakers must understand and plan for the implications of the ongoing evolution. With a focus on these challenges, the grid can become even more reliable and resilient. Throughout this transition, NERC plays a critical role in identifying, assessing, and addressing risks to help navigate the transition reliably. The Subcommittee is asking highly salient questions that are central to the nation's energy future and prosperity. I appreciate the opportunity to share NERC's perspective and expertise.

APPENDIX

This appendix includes summaries of recent NERC assessments which provide additional findings and recommendations.

Distributed Energy Resources: Connection, Modeling, and Reliability Considerations (February 2017)
Increasing amounts of distributed energy resources can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and essential reliability services. Attention must be paid to potential reliability impacts, the time frame required to address reliability concerns, coordination of essential reliability services and system protection considerations for both the transmission and distribution system, and the growing importance of information sharing across the transmission-distribution interface.

2016 Long-Term Reliability Assessment (December 2016)
NERC prepares seasonal and long-term assessments to examine current and future adequacy and operational reliability of the North American BPS. NERC's primary objective with this assessment is to assess resource and transmission adequacy across the NERC footprint, and to assess emerging issues that have an impact on BPS reliability over the next ten years.

A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, NERC (October 2014)
Conventional generation with large rotating mass (steam, hydro, and combustion turbine technologies) provide necessary operating characteristics, defined as essential reliability services, needed to operate the North American electric grid reliably. Essential reliability services represent a necessary and critical part of the fundamental reliability functions that are vital to ensuring reliability. They are key services and attributes that are needed to maintain operating reliability—primarily voltage and frequency support. Many of these services and attributes are provided by baseload conventional generating plants; however, as the resource mix changes, essential reliability services must be maintained.

Accommodating an Increased Dependence on Natural Gas for Electric Power (May 2013)
The combination of growth in natural gas demand within the electricity sector and its changing status among the gas-consuming sectors continues to significantly increase the interdependencies between the gas and electricity industries. As a result, the interface between the two industries has become the focus of industry discussions and policy considerations. In its effort to maintain and improve the reliability of the North American BPS, NERC examined this issue in detail and developed recommendations for the power industry. These recommendations will help improve existing coordination between the gas and electricity sectors and facilitate the reliable operation of the two industries.

Exhibit B

Synopsis of NERC Reliability Assessments
The Changing Resource Mix and the Impacts of Conventional Generation Retirements

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Gerry Cauley
President and Chief Executive Officer

May 9, 2017

The Honorable Rick Perry
Secretary
U.S. Department of Energy
1000 Independence Avenue
Washington, DC 20585-1000

Dear Secretary Perry:

The North American electric power system is undergoing a significant transformation with ongoing retirements of fossil-fired and nuclear capacity, while at the same time, experiencing growth in capacity fueled by natural gas, wind, and solar. This shift is caused by several drivers, such as federal, state, and provincial policies, low natural gas prices, electricity market forces, and integration of both distributed and utility-scale renewable resources. The changing resource mix is altering the operating characteristics of the bulk power system (BPS). In order to assure continued reliability, these changing characteristics must be well understood and properly managed. Understanding that the Department of Energy is reviewing these reliability matters, the accompanying document summarizes NERC's recent work in this area.

The North American Electric Reliability Corporation (NERC) has important responsibilities under federal law to assess the reliability of the BPS. NERC annually assesses seasonal and long-term reliability of the BPS and conducts special assessments relating to issues potentially impacting the reliable operation of the grid. The assessments summarized focus on the impacts from the changing resource mix on the reliability of the BPS, including increased dependency on natural gas, operating characteristics (essential reliability services) and distributed energy resources. By identifying and quantifying the impacts from emerging reliability concerns, NERC is able to provide risk-informed recommendations for their mitigation and support a learning environment for industry.

NERC is an independent, non-profit organization with a single focus on assuring the reliability and security of the grid. We have a strong partnership with DOE and can be a resource as you move forward on numerous policy initiatives.

I look forward to meeting with you on May 18 to discuss critical grid reliability and security issues, and our partnerships with DOE. I thank you for your attention to reliability and look forward to our discussion. In the meantime, please contact Mr. Fritz Hirst (fritz.hirst@nerc.net), NERC's Director of Legislative and Regulatory Affairs, with any questions.

Respectfully,

Gerry Cauley
President and CEO

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Synopsis of NERC Reliability Assessments

The Changing Resource Mix and the Impacts of Conventional Generation Retirements

Introduction

The North American electric power system is undergoing a rapid and significant transformation with ongoing retirements of fossil-fired and nuclear capacity, as well as growth in natural gas, wind, and solar resources. This shift is caused by several drivers, such as federal, state, and provincial policies, low natural gas prices, electricity market forces, and integration of both distributed and utility-scale renewable resources. The changing resource mix is altering the operating characteristics of the bulk power system (BPS). These changing characteristics must be well understood and properly managed in order to assure continued reliability and ensure resiliency.

Voltage control, frequency support, and ramping capability are essential to maintaining BPS reliability. Through this transition, policy makers and stakeholders must recognize the need to maintain these essential reliability services. It is also necessary to assure resilience measures, such as maintaining fuel diversity and new technologies that work with, not against, the BPS.

Growing reliance on natural gas continues to raise reliability concerns regarding the ability of both gas and electric infrastructures to maintain the BPS reliability at acceptable levels. Many efforts have focused on the gas-electric interface and yet, insufficient progress has been made reconciling the planning approaches and operating practices (scheduling situation awareness, information sharing) between these two inter-linked sectors. Planning approaches, operational coordination, and regulatory partnerships are needed to assure fuel deliverability, availability, security (physical and cyber), and resilience to potential disruptions. Unfortunately, an approach not obvious in electricity markets today.

Reliability and How the Changing Resource Mix Affects It

The North American BPS is designed to be a highly reliable, robust, and resilient system. The system is interconnected, and the integrated networks work together to maintain reliability through both wide-area interregional planning and coordinated system operations. The adequacy of the system is maintained by having the right combination and amount of resources and transmission to deal with unexpected facility outages or extreme weather events that increase system demand. Operating reliability is maintained in real-time through highly coordinated operator actions across many operating companies. The system is also planned as many as 15 years in advance by performing highly detailed, complex, and data-intensive power system simulations.

RELIABILITY

NERC defines the reliability of the interconnected BPS in terms of two basic and functional aspects:

Adequacy — The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and reasonably expected unscheduled outages of system components.

Operating Reliability — The ability of the electric system to withstand sudden disturbances to system stability or unanticipated loss of system components.

The resource mix of the BPS is changing in fundamental ways. Variable energy resources, especially wind and solar) are rapidly expanding and capturing the majority share of new capacity additions. Conventional generation (such as coal and nuclear) are retiring and have become economically

marginalized. The balancing resource tends to be natural gas as environmental rules and commodity economics tend to make oil fired generation uneconomic). Development of hydro-electric resources, a major energy source in some parts of the country such as the west, is extremely challenging. The confluence of the changing resource mix can fundamentally impact reliability in two major ways:

- A Balancing Authority responsible for managing the balance of demand and resources through unit commitment and forecasting may become capacity deficient and unable to serve firm load. Resources may not be available when needed, particularly those that have ***not*** secured on-site fuel. In that instance, manual load shedding may be required to maintain reliability.
- Large unanticipated voltage or frequency deviations during a disturbance can lead to uncontrolled, cascading instability. With no mass, moving parts, or inertia, increasing amounts of inverter-based resources (such as solar photovoltaic) present new risks to reliability, such as managing faster fault-clearing times, reduced oscillation dampening, and unexpected inverter action.

The rapid changes occurring in the generation resource mix and technologies are altering the operational characteristics of the grid and will challenge system planners and operators to maintain reliability. More specifically:

- Impact of Premature Retirements: Conventional units, such as coal plants, provide frequency support services as a function of their large spinning generators and governor-control settings along with reactive support for voltage control. Power system operators use these services to plan and operate reliably under a variety of system conditions, generally without the concern of having too few of these services available. Coal-fired and nuclear generation have the added benefits of high availability rates, low forced outages, and secured on-site fuel. Many months of on-site fuel allow these units to operate in a manner independent of supply chain disruptions.
- Replacement Resource Capability and Characteristics: As the generation resource mix evolves, the reliability of the electric grid depends on the operating characteristics of the replacement resources. Natural gas-fired units, variable generation, storage, and other resources can provide similar reliability services. However, as a practical matter, costs, market rules, or regulatory requirements (or lack thereof) can affect whether these resources are equipped and available to provide reliability services. To ensure reliability, new generator and load resources must maintain the balance between load and generation, especially during ramping periods. In addition, in some jurisdictions, substantial amounts of generation is now being added “behind the meter” (e.g., roof top solar) and these resources are invisible to system operators.

NERC and the ERO-Enterprise’s Role in Evaluating BPS Reliability

A comprehensive understanding of the complexity of the changing BPS is key to developing effective approaches for achieving reliability and resiliency. The North American Electric reliability Corporation (NERC) and eight regional Entities (the RE’s, or collectively the ERO-Enterprise) are charged with assuring the reliability of the BPS. NERC and RE experts work with industry leaders to create a reliability strategy that is relevant, timely, and effective with regard to addressing the highest priority reliability risks. The ERO-Enterprise maintains a technical framework and understanding of the reliability threats facing our industry and uses those insights to communicate guidance and information to entities and policy-makers across North America to enhance reliability. It accomplishes this through its own engineering and analytical efforts, as well as through marshaling stakeholder resources with subject matter expertise.

Our Reliability Assessments provide a technical platform for important policy discussions on challenges facing the interconnected North American BPS. Each year, the ERO-Enterprise independently assesses and reports on the overall reliability, adequacy, and associated risks that could impact the upcoming summer and winter seasons and the long-term, 10-year period. As emerging risks and potential impacts to reliability are identified, special assessments are conducted that provide similar technical framework and insights about the range and specific aspects of these to guide steps that may be warranted. Unbiased judgment of industry’s plans for maintaining

NERC

The North American Electric Reliability Corporation is a not-for-profit international regulatory authority whose mission is to assure the reliability and security of the bulk power system in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the bulk power system through system awareness; and educates, trains, and certifies industry personnel. NERC's area of responsibility spans the continental United States, Canada, and the northern portion of Baja California, Mexico. NERC is the electric reliability organization for North America, subject to oversight by the Federal Energy Regulatory Commission and governmental authorities in Canada. NERC's jurisdiction includes users, owners, and operators of the bulk power system, which serves more than 334 million people.

electric reliability in the future is founded on solid engineering through collaborative and consensus-based assessments.

By identifying and quantifying emerging reliability issues, we are able to provide risk-informed recommendations and support a learning environment for industry to pursue improved reliability performance. These recommendations, along with the associated technical analysis, provide the basis for actionable enhancements to resource and transmission planning methods, planning and operating guidelines, and NERC Reliability Standards.

The Reliability Assessment group conducts evaluations and reports that fulfill the statutory requirements of Section 215 in the Energy Policy Act of 2005.

Summary of Overarching Key Findings

As a common thread in each of our Reliability Assessments, the most pressing reliability issues in North America are:

- As conventional resources prematurely retire, sufficient amounts of essential reliability services, such as frequency and voltage support, ramping capability, etc., must be replaced based on the configuration and needs of the system.
- Resource flexibility is needed to supplement and offset the variable characteristics of solar and wind generation.
- Higher reliance on natural gas exposes electric generation to fuel supply and delivery vulnerabilities, particularly during extreme weather conditions. Maintaining fuel diversity and security provides best assurance for resilience. Premature retirements of fuel secure baseload generating stations reduces resilience to fuel supply disruptions.
- Because the system was designed with large, central-station generation as the primary source of electricity, significant amounts of new transmission may be needed to support renewable resources located far from load centers.

Summary of Recommendations

Three overarching recommendations for policy makers and stakeholders are the focus of our most recent reliability assessments:

- State regulators and market operators should give due consideration to the changing reliability aspects of the grid when considering resource needs, adequacy requirements, distribution-level interconnection requirements, and long-term resiliency. States and FERC should immediately review the economic and policy issues impacting fuel secure baseload generation in an effort to limit early closure of existing assets. States and FERC should ensure that required reliability characteristics are giving consideration when identifying future reliability and capacity needs.
- Regulators and policy makers should evaluate whether the natural gas regulatory framework for transportation priority and construction is compatible with the requirements of the changing BPS, which has significant amounts of natural gas generation, along with identifying a transition plan that provides certainty in the long-term. Market operators should also evaluate whether market rules should be revised to provide assurances that generators will perform in normal and extreme circumstances.

- NERC should conduct a comprehensive evaluation of its Reliability Standards to ensure compatibility with large amounts of non-synchronous resources, as well as for completeness of expectations related to essential reliability services, generator performance, and balancing. This review should include both non-synchronous resources connected directly to the BPS and distributed energy resources connected to the distribution system.

Key Concepts from NERC Reliability Assessments

- **What makes "baseload" generation so important for reliability?**
  There is a distinction between baseload generation and the characteristics of generation providing reliable "baseload" power. Baseload is a term used to describe generation that falls at the bottom of the economic dispatch stack, meaning they are the most economical to run. Coal and nuclear resources, by design, are designed for low cost O&M and continuous operation. However, it is not the economics nor the fuel type that make these resources attractive from a reliability perspective. Rather, these conventional steam-driven generation resources have **low forced and maintenance outage hours** traditionally and have **low exposure to fuel supply chain issues**. Therefore, "baseload" generation is not a requirement; however, having a portion of a resource fleet with high reliability characteristics, such as low forced and maintenance outage rates and low exposure to fuel supply chain issues, is one of the most fundamental necessities of a reliable BPS. These characteristics ensure that "baseload" generation is more resilient to disruptions.

- **What are the reliability benefits of having a diverse resource portfolio?**
  Fuel diversity provides a fundamental benefit of increased resilience. Without this diversity, the impact of rare events impacting availability of resources on the power system increases and are more likely the result of a common-mode failure impacting multiple generation or transmission facilities (e.g., extreme and prolonged cold weather event leads to freezing generator components, transmission line icing, fuel delivery disruption, etc.). **Areas with limited fuel and/or limited resource diversity may be challenged and should increase their attention to resiliency planning**, which requires a strong partnership with state regulators. With natural gas generation primed to continue its growth as the leading choice for new and replacement capacity, important distinctions around fuel security need to be incorporated into reliance and long-term planning at states and with market operators. Mainly, natural gas generation is fueled using just-in-time transportation and delivery, and therefore, is subject to interruption. Roughly 50 percent of natural gas generation resources are considered interruptible, and in constrained natural gas markets these units are not expected to be served during peak pipeline conditions. Many of these plants no longer have the option of burning a liquid fuel. Further, regardless of fuel service arrangements, natural gas generation is subject to curtailment during a force majeure event.

- **What are the challenges with natural gas generation becoming more "baseload?"**
  Natural gas provides "just-in-time" fuel; therefore, disruptions to the fuel supply can impact multiple generators that may be connected to the same supply chain. **Firm transportation, multiple pipeline connections, and dual-fuel capability can significantly reduce the risk of common-mode failure and wider-spread reliability challenges**. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can impact electric reliability. This level of reliability is not only needed to produce electricity during "average" conditions, but during extreme conditions where fuel supply chains can breakdown or fail. Additionally, since natural gas does not generally have on-site storage, its supply is threatened to disruption by pipeline failure that potentially can lead to the loss of a substantial amount of capacity and threaten the adequacy of the electric system. Regulatory action may be needed to better calibrate electric and gas industries due to regulatory differences in how infrastructure is planned with reliability given due consideration.

  Two major trends are contributing to changes in generator performance: 1) the retirement of large coal and nuclear generation and 2) the addition of large amounts of solar and wind resources. Natural gas generation can be a very flexible resource—particularly combustion turbines. The ability to balance the variability of

solar and wind resources make them very attractive. However, the more they are being used as a "baseload" resource (i.e., higher capacity factor), the less they can be used to provide flexibility to the system. Additionally, **as cycling increases, generator's experience higher forced outage rates and require more maintenance**. This is a common challenge with all thermal-based conventional generation.

Finally, expansion of natural gas and its transition from a "supplemental resource" to the "primary resource" is creating challenges. Natural gas infrastructure has proven to be reliable, but not designed to meet the electric sector needs. Natural gas infrastructure is optimized for economics, not reliability. As a result, it tends to be based on large single elements. When problems occur with major elements, they can significantly disrupt the power system. For example, the operational challenges faced by the BES, and specifically the Los Angeles and greater Southern California area due to the loss of the Aliso Canyon gas storage facility. Also, a major disruption on a key pipeline could also interrupt fuel supply for thousands of megawatts of generation, because it is a common-mode element.

- **How do resource mix changes impact the pace at which infrastructure can be developed?**
  From an adequacy perspective, the existing transmission system was planned and designed to support the existing generation fleet, which is comprised mostly of larger, central-station electric generation. Therefore, accommodating new resources, particularly those located in areas different from the existing fleet, transmission lines, facilities, and/or other transmission elements will likely be necessary. Generation retirements can happen quickly, but adequate replacement facilities must be in-service prior to retirement.

  The lead times required and associated uncertainties for the planning, engineering, permitting, and construction of new generating resources, transmission facilities, and fuel infrastructure adds complexity to the pace at which new facilities can be built. Uncertainty in the timing of such resource decisions and the ability to construct the necessary energy infrastructure to implement those decisions stems from the following factors:

  - The addition of new generating resources can take several years to permit and construct. There will be a range of time periods depending on the circumstances related to each project, including regulatory approvals at various state, municipal, county, federal, and provincial levels, secured financing and fuel supply chain, and the availability of construction crews and equipment.
  - Changes to resources (such as retirements or new generation) can require a need for additional electric transmission infrastructure. Such transmission can require many years to permit and construct, typically longer than generation construction, and timing will depend on the facts and circumstances of each project.
  - Where new or repowered generating resources are dependent on natural gas as a fuel, there will be a requirement for additional gas pipeline infrastructure. Depending on the location of the plant relative to interstate gas pipelines, plant-specific gas infrastructure will require several years to permit and construct. The resource decisions of neighboring states can also impact the transmission infrastructure required to maintain reliability within a given state.

Reliability Assessments from NERC and the Regional Entities

- ### 2016 Long-Term Reliability Assessment, NERC (December 2016)

  Summary: NERC prepares seasonal and long-term assessments to examine current and future adequacy and operational reliability of the North American BPS. NERC's primary objective with this assessment is to assess resource and transmission adequacy across the NERC footprint, and to assess emerging issues that have an impact on BPS reliability over the next ten years.

Key Findings:

- **Resource Adequacy:** Factors that are included when performing a resource adequacy assessment include a reserve margin analysis and the study of emerging reliability issues that can impact generation and demand projections. The results of this study identified four assessment areas as having a medium resource adequacy risk in the first five years of the assessment period.
- **Single-Fuel Dependency:** NERC has identified that reliance on a single fuel increases vulnerabilities, particularly during extreme weather conditions. Over the past decade, several areas have significantly increased their dependence on natural gas. This trend has continued amidst historically low natural gas prices and regulatory rulings that continue to promote increased natural gas generation. The Aliso Canyon outage in Southern California illustrates the effects of a potential single point of disruption. This one underground gas storage facility in SoCal Gas' service territory contains 86 BCF of gas capacity, providing fuel to approximately 9,800 MWs of electric generation. The facility also supports ramping requirements to accommodate the variability of renewable energy resources. This outage has the potential to cause rolling black outs in Southern California until the facility is completely operational again or other mitigation approaches have been employed.
- **Nuclear Uncertainty:** Low natural gas prices continue to affect the competitiveness of nuclear generation and are a key contributing factor to nuclear generation's difficulty in remaining economic with competing fuel sources. While new nuclear facilities are being built in Georgia, Tennessee, and South Carolina, potential retirements have been announced for nuclear facilities in Illinois, California, Nebraska, Massachusetts, and New York, creating longer-term uncertainty for system planners.
- **Distributed Energy Resources:** Increasing installations of distributed energy resources modify how distribution and transmission systems interact with each other. Many utilities currently lack sufficient visibility and operational control of these resources, increasing the risk to BPS reliability. This visibility is a crucial aspect of power system planning, forecasting, and modeling that requires adequate data and information exchanges across the transmission and distribution interface.

Recommendations:

- As the resource mix changes, the need for more investments in transmission and natural gas infrastructure is projected. The lengthy lead times involved in acquiring, siting, and permitting for infrastructure should also be considered when assessing reliability impacts.
- As natural gas-fired resources continue to increase, system planners, and operators should evaluate the potential effects of an increased reliance on natural gas on BPS reliability. As part of future transmission and resource planning studies, planning entities will need to more fully understand how impacts to the natural gas transportation system can affect electric reliability.
- Regulators and legislators should consider the uncertainties in resource retirements and resource mix changes projected by resource planners. The implementation of a regulatory framework (e.g., interconnection requirements) that helps ensure an adequate level of essential reliability services could help to address these uncertainties.

Report Link: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf

Letter from Jim Robb (CEO WECC) to Michael Picker, President of the CPUC (appendix to this document)

- **A Concept Paper on Essential Reliability Services that Characterizes Bulk Power System Reliability, NERC (October 2014)**

Summary: Conventional generation with large rotating mass (steam, hydro, and combustion turbine technologies) provide necessary operating characteristics, defined as essential reliability services, needed to reliably operate the North American electric grid. Essential reliability services represent a necessary and critical part of the fundamental reliability functions that are vital to ensuring reliability. They are key services and attributes that are needed to maintain operating reliability—primarily voltage and frequency support. Many of these services and attributes are provided by baseload conventional generating plants; however, as the resource mix changes, NERC must ensure that essential reliability services are maintained.

Key Findings:

- Generating resources need to be able to provide voltage control, frequency support, and ramping capability as essential reliability services to balance and maintain the electric grid. Without these characteristics, the grid could not be operated reliably.
- Federal, state, and local jurisdictional policy decisions have a direct influence on changes in the resource mix and can also affect the reliability of the electric grid. As resources retire, in addition to replacing lost capacity, it is necessary for policy decisions to recognize the need for essential reliability services from the current and future mix of resources.
- Some variable energy resources and storage technologies can contribute to essential reliability services; however, policies and market mechanisms may not provide enough incentive or clarity to ensure these services are maintained across the system.

Recommendations:

- All new resources should have the capability to support voltage and frequency. Ensuring that these capabilities are present in the future resource mix is prudent and necessary.
- Monitoring of the essential reliability services measures, investigation of trends, and use of recommended industry practices will highlight aspects that could become reliability concerns if not addressed with suitable planning and engineering practices.
- Distributed energy resources will increasingly impact the planning and operation of the grid. The task force recommends further examination of the forecasting, visibility, and participation of distributed energy resources as an active part of the electric grid.

Abstract: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERS%20Abstract%20Report%20Final.pdf
Report Link: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/ERSTF%20Concept%20Paper.pdf
Multi-Media Link: https://vimeopro.com/nerclearning/erstf-1

- **Distributed Energy Resources: Connection, Modeling, and Reliability Considerations, NERC (February 2017)**

Summary: Increasing amounts of distributed energy resources can change how the distribution system interacts with the BPS and will transform the distribution system into an active source for energy and essential reliability services. Attention must be paid to potential reliability impacts, the time frame required to address reliability concerns, coordination of essential reliability services and system protection considerations for both the transmission and distribution system, and the growing importance of information sharing across the transmission-distribution interface.

Key Findings:

- **Modeling and Data Requirements**: The effect of aggregated distributed energy resources is not fully represented in BPS models and operating tools. This could result in unanticipated power flows and increased demand forecast errors.
- **Frequency and Voltage Ride-Through:** Distributed energy resources are not coordinated with the voltage and frequency ride-through requirements of NERC Reliability Standard PRC-024-2.
- **System Protection:** Distributed energy resources are not completely coordinated with under frequency load shedding (UFLS) and under voltage load shedding (UVLS) programs or other system protection measures. High levels of distributed energy resources with inverters can also result in a decline in short circuit current, which can make it more difficult for protection devices to detect and clear system faults.

Recommendations:

- **Guidelines**: The Distributed Energy Resources Task Force recommends that a set of guidelines be developed to assist in modeling and assessments, such that owners and operators of the BPS can account for the impact of distributed energy resources.
- **Data Sharing**: Data requirements and sharing of information across the transmission-distribution interface should be further evaluated to allow for adequate assessment of future distributed energy resources deployments.
- **Modeling:** Based on reliability considerations for modeling purposes, generation from distributed energy resources should not be netted with load as penetration increases. Load and distributed energy resources should be explicitly modeled in 1) steady-state power flow and short-circuit studies and 2) dynamic disturbance ride-through studies and transient stability studies for BPS planning with a level of detail that is appropriate to represent the aggregate impact of distributed energy resources on the modeling results over a five- to 10-year planning horizon.
- **Coordination:** A coordinated effort by transmission and distribution entities is needed to determine the appropriate use of future distributed energy resources capabilities (such as settings available under proposed IEEE 1547 revisions). This must be coordinated with voltage and frequency ride-through performance and potentially coordinated with UFLS programs and BPS performance under PRC-024. Note that PRC-024 was developed with BPS issues in mind and where PRC-024-2 and desired distribution-level protection and operations conflict, the transmission and distribution utilities will need to coordinate the required distributed energy resources ride-through settings to meet BPS reliability needs while minimizing distribution impact.

Report Link: http://www.nerc.com/comm/Other/essntlrlbltysrvcstskfrcDL/Distributed_Energy_Resources_Report.pdf

- **Western Interconnection Flexibility Assessment, WECC (December 2015)**

Summary: With growing penetrations of renewable resources, new challenges will arise for resource planners and operators. The report assesses the ability of the fleet of resources in the Western Interconnection to accommodate high renewable penetrations while maintaining reliable operations. Higher penetrations of renewable generation will test the flexibility of the electric systems by requiring individual power plants to operate in fundamentally new ways, changing operating practices as well as the dynamics of wholesale power markets.

Wind and solar resources, which will likely account for a significant share of the additional renewable generation in the Western Interconnection, are characterized by three key attributes that have important implications for power system operations:

- **Variability:** production changes from moment to moment, and from hour to hour;
- **Uncertainty:** production over a given period of time cannot be predicted with perfect accuracy; and
- **Concentration:** production is highly concentrated during certain hours of the year in which the resource is available.

As the penetrations of variable renewable resources in the Western Interconnection continue to increase, planners must confront the question of how to build and operate a reliable system in which a large portion of the energy available has these qualities.

Key Findings:

- The analysis conducted in this study identifies no technical barriers to the achievement penetrations of renewable generation of up to 40 percent of total supply in the Western Interconnection.
- Because the penalty prices for unserved energy and curtailment prioritize load service over the delivery of renewable generation, renewable curtailment is the key indicator of a system that is constrained in its ability to integrate renewables.
- Routine, automated renewable curtailment is a fundamental necessity to electric systems at high renewable penetrations, as it provides operators with a relief valve to manage net load conditions to ensure a system can be operated reliably at increasing penetrations. Renewable curtailment is identified as the “default solution” to flexibility challenges as it represents a last recourse for system operators—prior to shedding load—once the flexibility of the existing traditional dispatchable system has been exhausted. However, there are many options for alternative strategies that, if identified and deployed in advance, can provide operators with additional flexibility and mitigate the need to curtail renewable generation.
- While renewable curtailment is identified as the predominant challenge in operations at high renewable penetrations, its magnitude can be mitigated through efficient coordination of operations throughout the Western Interconnection.

Recommendations:

- To facilitate increased coordination in operations, the report recommends increased regional coordination and scheduling, investments in energy storage technologies, and investments in flexible gas generation.
- System operators must fully understand the conditions and circumstances under which renewable curtailment is necessary or desirable.
- The consequences of extended periods of negative pricing must be examined and understood.

Report Link: https://www.wecc.biz/Reliability/WECC_Flexibility_Assessment_Report_2016-01-11.pdf

- **Accommodating an Increased Dependence on Natural Gas for Electric Power, NERC (May 2013)**

Summary: The combination of growth in natural gas demand within the electricity sector and its changing status among the gas-consuming sectors continues to significantly increase the interdependencies between the gas and electricity industries. As a result, the interface between the two industries has become the focus of industry discussions and policy considerations. In its effort to maintain and improve the reliability of the North American BPS, NERC examined this issue in detail and developed recommendations for the power industry. These recommendations will help improve existing coordination between the gas and electricity sectors and facilitate the reliable operation of the two industries.

Key Findings:

- Gas use is expected to continue to increase in the future, both in absolute terms and as a share of total power generation and capacity. Unlike coal and fuel oil, natural gas is not easily stored on-site. As a result, real-time delivery of natural gas through a network of pipelines and bulk gas storage is critical to support electric generators.
- Natural gas is widely used outside the power sector, and the demand from other sectors—particularly coincident end-user gas peak demand during cold winter weather—critically affects the ability to deliver interruptible transportation service in the power sector. Additionally, demand for natural gas is expected to grow in other sectors (e.g., transportation, exports, and manufacturing).
- While extremely rare, disruptions in natural gas supply and/or transportation to power generators have prompted industry to seek an understanding of the reliability implications associated with increasing gas-fired generation. Contracts for firm natural gas supply and transportation affect the risk profile of each power plant (or group of power plants).
- Natural gas is expected to play a growing role in offsetting the variability and uncertainty associated with renewable resources. As variable generation increases, swings in variable generation may call for dispatch of gas-fired generation at a larger and less predictable rate.

Recommendations:
Policy makers, market operators, and asset owners should consider factors that reduce risk, such as:

- **Maintaining Alternative Fuel Capabilities:** Evaluate capabilities across generator fleet, maintain back-up fuel inventories at key stations, and annually test fuel switching capability.
- **Enhancing Market and Regulatory Rules:** Provide additional incentives for behavior and investments that support reliability and resiliency.
- **Evaluating Single Points of Disruption:** Assess reliability under extreme conditions, loss of major pipeline infrastructure, or supply.
- **Continuing Pipeline Expansion:** Keep pace with generation expansion and increasing electricity production.
- **Limiting Exposure to Supply Chain Failures:** Increase resiliency by maintaining alternative supply chains and paths.
- **Maintaining Situational Awareness:** Electric system operators need awareness of pipeline conditions and must be able to predict generators that may become unavailable.

- **Communicating Risks to Policymakers:** Results and conclusions of studies that evaluate electric reliability should be shared and clarified with policymakers and regulators.
- **Maintaining Fuel Diversity**: Maintaining fuel diversity provides inherent resiliency to common-mode risk.

Report Link: http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_PhaseII_FINAL.pdf

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MEMO

Date: June 22, 2016

To: Michael Picker, President of the California Public Utilities Commission

Subject: WECC Electric Reliability Analysis of Issues Related to Aliso Canyon

President Picker:

I am responding to your request that WECC provide its view of the reliability issues created by the situation at the Aliso Canyon natural gas storage facility. As you know, WECC is the Regional Entity responsible for assuring the reliability of the Bulk Electric System in the Western Interconnection. The limited ability to draw from Aliso Canyon is likely to cause electric generation fuel supply challenges in Southern California. During this challenging energy supply situation, WECC's chief concern will be that the reliability of the broader interconnection is protected. To this end, WECC conducted an independent assessment of potential impacts to the electric system resulting from potential fuel limitations in Southern California stemming from the Aliso Canyon issues. In this letter I highlight some of the key takeaways from that analysis and would like to express our appreciation for the transparency and collaboration taking place among affected entities.

We performed two types of analyses: a resource adequacy assessment to determine whether the Interconnection has enough generation to support Southern California's needs, and a series of power system contingency analyses to understand how the entire system performs under different stressors. Overall, our studies showed no major Interconnection-wide impacts but did reveal important operational considerations for Southern California.

A key element to preserving electric reliability in Southern California is the ability to supply an adequate level of imports to support its needs under a range of conditions. To study this, we used our established annual resource adequacy assessment with assumptions changed to reflect potential local supply conditions in Southern California this summer. The study showed adequate generation across the Interconnection to supply Southern California in all but the most extreme scenarios. It is important to note that this type of study assumes that generating resources are available to generate when called upon and that the power can get to where it needs to go—it does not address restrictions in deliverability.

To address deliverability, WECC regularly uses advanced study tools to identify system stability power flow issues. We used this capability to study the potential operational impacts to the Interconnection and Southern California. We created a baseline for comparison using our 2016 "Heavy Summer Base

Case," a model of the Interconnection that assumes high summer loads and moderate power transfers to reflect a stressed system scenario. From here, we created two comparison cases to reflect potential conditions in Southern California, one with all of the natural gas generation in the L.A. Basin at minimum output and one with it all turned off. We chose these cases specifically because they are expected to emphasize potential negative study results, making them worst-case bookends. We then tested these cases by applying a number of contingencies, or hypothetical system element outages.

In running the model, we were concerned with the following indicators of system health:

- Generation availability and unit stability – With low generation in the L.A. Basin, would there be sufficient resources elsewhere to replace the generation?
- Overloading of transmission lines – Assuming the resources are available, can they be imported without causing overloading of transmission lines and exceedances of WECC Transmission Path Ratings?
- Voltage stability – With low generation in the L.A. Basin, would there be sufficient voltage support in the area to maintain acceptable transmission and distribution voltages?

There are four takeaways from our power system contingency analyses:

- There is a minimum amount of generation that must be online in the L.A. Basin to provide voltage support to the local system and allow power to be imported. Without this generation, there is a high likelihood of voltage collapse within the L.A. Basin and concomitant risk to the interconnection if such a collapse is not quickly isolated. LADWP and CAISO have the detailed tools to determine the minimum level of generation that must remain online for system stability and have estimated 1300 MW to be the "must-run" capacity to support transmission import capability. Our analytics have affirmed that this is a reasonable estimate.
- The generation facilities capable of producing reactive power to provide voltage support include the natural gas facilities in the L.A. Basin. Some of these units are dual-fuel units and were designed with the capability to burn distillate. The ability to run these plants on an alternative fuel, other than natural gas, will help ensure adequate minimum levels of generation when gas supply is scarce.
- The location of the online generation within the L.A. Basin is critical to stability. Certain combinations of online units can lead to poor voltage support or additional stress on the transmission system in the L.A. Basin area due to unusual or abnormal power flows. CAISO will be in the best position to determine the correct units to run in real time based on the actual operating configuration of the system.
- Communication and collaboration among the affected entities is critical. This situation highlights the interdependency of the gas and electric infrastructures and operating protocols.

The high level of communication and information sharing occurring now between the entities will need to be closely managed throughout the summer and until the Aliso Canyon natural gas storage facility can be further utilized.

It is important to note that this study assumes all normally operating transmission lines in the L.A. Basin, and the rest of the interconnection, are in service. The study also assumes availability of the additional generating resources used in the simulations. If either transmission or generation capacity is limited for any reason (e.g., a fire that takes out multiple transmission lines, unforeseen events that result in the unavailability of major generating resources such as gas constraints or unscheduled maintenance), the additional stress to the Western Interconnection could result in negative impacts that have not yet been identified.

I hope you find this assessment useful in your policy deliberations. We believe very positive steps are in place to preserve electric reliability in Southern California. First are the recent actions to allow at least some of the Aliso Canyon facility to be used this summer to support the L.A. Basin electric system. Second are the conditional waivers issued by SCAQMD to allow LADWP to burn distillate under certain circumstances. We continue to be impressed with the coordination between the affected entities and involved agencies in California and believe it will serve the state well through this energy supply challenge. We are appreciative of the transparency with which LADWP, CAISO, and SoCal Gas have dealt with this issue and allowing us to be directly involved in the winter studies. We have also been coordinating closely with Peak Reliability and it appears they are taking appropriate steps to execute their responsibilities to protect the broader interconnection from any cascading outages.

Please feel free to contact me if you would like to discuss this analysis further. We look forward to continuing to work with the Western states, CAISO, LADWP, and Peak Reliability on this important matter.

Cc: Dr. Robert Weisenmiller, Chairman of the California Energy Commission

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RR17-6-000**

MOTION FOR LEAVE TO ANSWER JOINT COMMENTS OF THE ALBERTA ELECTRIC SYSTEM OPERATOR, THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION, THE INDEPENDENT ELECTRICITY SYSTEM OPERATOR, ISO NEW ENGLAND, INC., AND PJM INTERCONNECTION, LLC

Pursuant to Rules 212 and 213 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") Rules of Practice and Procedure, 18 C.F.R. §§ 385.212 and 385.213, the North American Electric Reliability Corporation ("NERC")[1] hereby moves to answer the Joint Comments of the Alberta Electric System Operator, the California Independent System Operator Corporation, the Independent Electricity System Operator, ISO New England, Inc., and PJM Interconnection, LLC ("Joint Comments")[2]. The Joint Comments merit a response to ensure that the Commission has an accurate record regarding the difference between the intent of Reliability Standard PER-005-2 (Operations Personnel Training) and the Continuing Education Program for the Personnel Certification Program under Sections 900 and 600 of the NERC Rules of Procedure ("ROP").

[1] The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

[2] Joint Comments of Alberta Electric System Operator, the California Independent System Operator Corporation, the Independent Electricity System Operator, ISO New England, Inc., and PJM Interconnection, LLC, Docket No. RR17-6-000 (July 17, 2017) (hereinafter "Joint Comments").

I. NOTICES AND COMMUNICATIONS

Notices and communications concerning these comments should be addressed to:[3]

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II. MOTION FOR LEAVE TO ANSWER

Given that the Joint Comments request that the Commission reject and remand the proposed changes to the NERC Rules of Procedure[4], the Joint Comments should be considered a protest. The Commission's rules generally do not permit the filing of answers to protests; however, the Commission has granted leave to file such answers if they clarify the issues in dispute, ensure a complete and accurate record, or otherwise provide information that will assist the Commission in its decision-making process.[5] To ensure that the Commission has complete and accurate

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[3] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2017), to allow the inclusion of more than two persons on the service list in this proceeding.

[4] 16 U.S.C. § 824o (2012).

[5] *See, e.g., San Diego Gas & Elec. Co. v. Sellers of Energy and Ancillary Servs.*, 108 FERC ¶ 61,219, at P 14, n. 17 (2004) (answer was accepted as it "provided information that assisted [the Commission in its] decision-making process"); *Mich. Elec. Transmission Co., LLC*, 106 FERC ¶ 61,064, at P 3 (2004) (the permitted answer "provides information that clarifies the issues and aids us in the decisional process"); *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062, at P 24 (2006) (reply comments of NERC and others accepted "because they have provided information that assisted us in our decision making process"); *N. Am. Elec. Reliability Corp.*, 117 FERC ¶ 61,091, at P 18 (2006) (same); *N. Am. Elec. Reliability Corp.*, 119 FERC ¶ 61,248, at P 6 (2007); *N. Am. Elec. Reliability Corp.*, 127 FERC ¶ 61,209, at P 5 (2009).

information upon which to make a decision on the proposed changes to the NERC ROP, NERC requests leave to submit this Answer to the Joint Comments.

III. The Personnel Certification Program and the Continuing Education Program are Not Redundant with PER-005-2.

Reliability Standard PER-005-2 establishes an internal training requirement for a broad group of personnel at Reliability Coordinators, Transmission Operators and Balancing Authorities. Specifically, it applies to System Operators, Generator Operators and Operations Support personnel. Pursuant to Requirement R1, each Reliability Coordinator, Transmission Operator and Balancing Authority must use a "systematic approach to develop and implement a training program" for these personnel. This training program is an in-house training program tailored to the needs of the organization. The required "systematic approach" is designed to determine "(1) the skills and knowledge necessary for the position in question; (2) the type of training needed to provide the trainee the identified skills and/or knowledge; (3) whether the trainee can competently perform his/her job function; and (4) whether the training is effective or requires adjustment." Requirement R1.1.4 further requires these entities to "conduct an evaluation each calendar year" of their training programs. Ultimately, entities subject to this Reliability Standard retain the discretion to apply these principles of a systematic approach to training to develop and implement training requirements for their applicable personnel. Through this Reliability Standard, NERC does not dictate a minimum threshold of competency for any personnel. Different entities may identify different skills and/or knowledge for their applicable personnel.

In contrast to PER-005-2, Section 600 of the NERC ROP establishes a program which awards a credential for system operators who pass the Personnel Certification Program examination. Passing this examination signifies that a system operator has essential knowledge of

NERC Reliability Standards and principles for Bulk-Power System operations. System operators with this credential maintain it by obtaining Continuing Education credits through the Continuing Education Program under section 900 of the NERC ROP. The existence of this credential and the requirements for maintaining it are the responsibility of the Personnel Certification Governance Committee and the Personnel Subcommittee which report to the NERC Board of Trustees. Training requirements for System Operators, Generator Operators and Operations Support personnel under PER-005-2 are the responsibility of the training programs at those entities. PER-005-2 does not mandate that all training programs qualify for credit towards maintaining the NERC-awarded credential.

If a Reliability Coordinator, Transmission Operator or Balancing Authority opts to have one of its PER-005-2 mandated training courses qualify as an approved learning activity for certified system operators under section 900 of the NERC ROP, then it must submit an Individual Leaning Activity application to NERC. NERC reiterates that Reliability Coordinators, Balancing Authorities and Transmission Operators may offer courses and train on topics relevant to their personnel; however, not all training courses that they offer will qualify as learning activities for system operators. Any proposals to re-examine credential renewal or maintenance should be raised with the industry-led Personnel Certification Governance Committee.

IV. CONCLUSION

For the reasons set forth above, NERC requests that the Commission approve the proposed revisions to the NERC ROP included in **Exhibits A-B**.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

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Date: October 17, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service lists compiled by the Secretary in Docket No. RR17-6-000.

Dated at Washington, DC this 17th day of October, 2017.

/s/ Courtney M. Baughan

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability	**)**	
Corporation	**)**	**Docket No. FA11-21-000**

COMPLIANCE FILING OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

I. INTRODUCTION

The North American Electric Reliability Corporation ("NERC")[1] submits this compliance filing in accordance with the Commission's January 16, 2013 Order in Docket No. FA11-21-000.[2] In the January 16 Order, the Commission approved a Settlement Agreement between the Office of Enforcement ("Enforcement") and NERC related to Enforcement's findings and recommendations arising out of its 2012 performance audit of NERC. Specifically, Section II.7(b)(i) of the Settlement Agreement requires that:

> Within forty-five days of the end of each quarter, beginning with the quarter ending March 31, 2013, NERC will file with the Commission the unaudited report of the NERC budget-to-actual spending variances during the preceding quarter. This report will include information regarding sources and uses of operating and working capital reserves and will match or exceed the level of detail of the quarterly budget-to-actual variance report of NERC expenditures attached to the agenda of NERC Board of Trustees Finance and Audit Committee's October 2012 meeting.[3]

Attached hereto is the unaudited report of NERC's budget-to-actual variance information for the third quarter of 2017, in accordance with the January 16 Order. This variance information

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[1] NERC was certified by FERC as the electric reliability organization ("ERO") authorized by Section 215 of the Federal Power Act. FERC certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *Order Certifying North American Electric Reliability Corporation as the Electric Reliability Organization and Ordering Compliance Filing*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order").

[2] *See North American Electric Reliability Corporation, Order Approving Settlement Agreement*, 142 FERC ¶ 61,042 (2013) ("January 16 Order").

[3] *Id.*

was posted on NERC's website November 1, 2017 and reviewed at the November 8, 2017 open meeting of the NERC Finance and Audit Committee. The unaudited report was accepted by the NERC Board of Trustees at its meeting on November 9, 2017.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:

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III. DISCUSSION OF SIGNIFICANT VARIANCES BETWEEN 2017 BUDGET AND PROJECTED ACTUAL 2017 RESULTS

The attached third quarter 2017 variance report compares actual (unaudited) financial results to NERC's budgeted expenditures as of September 30, 2017, and projected year-end 2017 financial results to NERC's total 2017 budgeted expenditures. NERC is providing additional discussion of significant variances between the actual (unaudited) third quarter results and NERC's budgeted expenditures, by NERC department or program area and by major activity within departments and program areas. For purposes of this discussion, NERC has focused on actual cost variances in excess of budget of $500,000 or more, because Section 7(b)(ii) of the Settlement Agreement specifies that NERC will file for Commission review and approval proposals approved by the NERC Board of Trustees to expend $500,000 or more from Operating Reserves designated for "unforeseen contingencies" (as defined in NERC's Working Capital and

Operating Reserves Policy), *i.e.*, where any amount allocated from the unforeseen contingencies account of Operating Reserves plus any amount redirected from previously budgeted funds is, in the aggregate, $500,000 or more for any one specific project or major activity in a program area.

A. Consultants and Contracts

Expenses related to the Consultant and Contract category of expenditures were under budget $1.0M (10.1%), and are projected to be $1.3M (10.1%) over budget at year-end. $865k of this projected over budget variance relates to the Cyber Risk Information Sharing Program ("CRISP"), including start-up costs for new participants and a security review engagement, and will be funded by CRISP participants. Furthermore, the projected total over budget variance includes expenses for the E-ISAC portal improvement project ($449k) and the system operator certification ("SOCCED") database replacement project ($189k, funded by SOCCED reserves). The additional consultant and contract costs related to the E-ISAC portal project are offset by spending reductions in fixed assets (where the project was originally budgeted), and the total projected 2017 spending is under budget.

B. Fixed Assets

Net fixed asset expenditures were $2.1M (62.7%) under budget through the third quarter and are projected to be $1.1M (24.4%) under budget at year-end. The under budget variance is primarily related to the accounting treatment of software projects and the leasing of audio/visual equipment, which were both originally budgeted in fixed assets.

C. Compliance Analysis, Certification and Registration Program

Actual 2017 direct expenses plus net fixed asset expenditures for the Compliance Analysis, Certification and Registration Program are projected at year-end to be $917k (54.4%) more than budgeted, primarily due to the allocation of additional staff resources to support

program activities ($354k), and costs related to designing a new entity registration database ($479k). Costs associated with the entity registration database were budgeted in IT as part of the ERO Enterprise application development budget, but will be charged to the Compliance Analysis, Certification and Registration Program to match costs with the relevant operating program utilizing the application.

D. Reliability Risk Management

Actual 2017 direct expenses plus net fixed asset expenditures for the Reliability Risk Management Program are projected at year-end to be $506k (6.7%) more than budgeted, primarily due to the costs related to two IT projects, MIDAS and FERC 854, totaling $463k. Costs associated with these two projects were budgeted in IT as part of the ERO Enterprise application development budget, but will be charged to the Reliability Risk Management Program to match costs with the relevant operating program utilizing the application, which has no impact on NERC's overall budget.

E. Information Technology

Actual 2017 direct expenses plus net fixed asset expenditures for the Information Technology department are projected to be $969k (7.8%) under budget, primarily related to certain ERO development projects transferred to program areas, as described above.

F. Operating Reserves

Through the third quarter, $85k of operating reserves were utilized to fund an ERO leadership conference, and $79k of SOCCED reserves have been utilized to fund the new SOCCED database project and operations. The SOCCED department is projecting to use an additional $168k in reserves to complete the database project and fund estimated net operating

costs. The use of SOCCED reserves is approved by the Personnel Certification Governance Committee.

G. Board of Trustees Expenses

Through the third quarter, a total of $1.3M was budgeted for Board of Trustee expenses and $1.2M was incurred. Board of Trustee expenses are projected to be under budget at year-end. The under-budget variance is primarily due to two Board of Trustee vacancies that occurred after the second quarter of 2017, and the positions are expected to be filled in February 2018.

CONCLUSION

NERC respectfully requests that the Commission accept this filing as compliant with Section II.7(b)(i) of the Settlement Agreement and the Commission's January 16 Order in Docket No. FA11-21-000.

Respectfully submitted,

/s/ Meredith M. Jolivert

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Counsel for North American Electric Reliability Corporation

Dated: November 13, 2017

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 13th day of November, 2017.

/s/ Meredith M. Jolivert

Meredith M. Jolivert
Counsel for North American Electric Reliability Corporation

ATTACHMENT

Summary of Unaudited Results
For the Month ending September 30, 2017

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Executive Summary

NERC 2017 - Year-end Projected Results
As of September 30, 2017
($ millions)

FUNDING	Projected	Budget	Over (Under)
Revenues	$ 69.4	$ 69.1	$ 0.3
Funding from Reserves			
Assessment Stabilization Reserve	1.1	1.1	-
SOCCED	0.2	-	0.2
Future Obligation	0.1	-	0.1
Operating Contingency	0.1	-	0.1
TOTAL FUNDING	$ 70.9	$ 70.2	$ 0.7
EXPENDITURES			
Expenses (excluding Depreciation)	$ 66.6	$ 65.2	$ 1.4
Fixed Asset Additions	3.3	4.4	(1.1)
TOTAL EXPENDITURES	$ 69.9	$ 69.6	$ 0.3
RESERVE INCREASE (DECREASE)	$ 1.0	$ 0.6	$ 0.4

FUNDING

- Revenues
  - CRISP funding projected to exceed budget due to new participant start-up costs and additional funding for a security review
  - Interest income higher than budget; testing fees lower than budget
- Funding from Reserves
  - SOCCED – Planned use of reserve funding for operations and projects
  - Future Obligation[1] – Planned use for IT projects from 2016 (funds held from prior year)

EXPENDITURES

- Expenses
  - Additional CRISP costs due to new participant start-ups and security review
  - Expected to be over-budget for projects budgeted in fixed assets, but recognized here
- Fixed Assets
  - Expected to be under-budget for projects budgeted here but recognized as an expense

RESERVE INCREASE (DECREASE)

- Anticipate larger than expected increase in total reserves

[1] *Excludes the budgeted use of deferred rent reserves, which is recorded as a direct adjustment to rent expense. Office rent expense is being budgeted and amortized on a straight-line basis over the lease term, which varies from the actual cash amount paid.*

NERC 2017 - Actual Results
As of September 30, 2017
($ millions)

FUNDING	Actual	Budget	Over (Under)
Revenues	$ 54.7	$ 53.5	$ 1.2
Funding from Reserves			
Assessment Stabilization Reserve	1.1	1.1	-
SOCCED	0.2	-	0.2
Future Obligation	0.1	-	0.1
Operating Contingency	0.1	-	0.1
TOTAL FUNDING	$ 56.2	$ 54.6	$ 1.6
EXPENDITURES			
Expenses (excluding Depreciation)	$ 48.2	$ 49.3	$ (1.1)
Fixed Asset Additions	1.2	3.3	(2.1)
TOTAL EXPENDITURES	$ 49.4	$ 52.6	$ (3.2)
RESERVE INCREASE (DECREASE)	$ 6.8	$ 2.0	$ 4.8

FUNDING

- Revenues – CRISP additional participant funding
- Funding from Reserves
  - SOCCED – Planned use of reserve funding for operations
  - Future Obligation[2] – Planned use for IT projects from 2016 (held from prior year)

EXPENDITURES

- Expenses
  - Additional CRISP costs due to new participant start-ups and security review
  - Several projects under budget due to timing differences of spending
- Fixed Assets
  - Some projects budgeted as fixed assets are being recorded as expense
  - Timing differences in spending

RESERVE INCREASE (DECREASE)

- Greater increase in reserves than anticipated year-to-date primarily because of CRISP funding and lag in timing of expenses

[2] *Excludes the budgeted use of deferred rent reserves, which is recorded as a direct adjustment to rent expense. Office rent expense is being budgeted and amortized on a straight-line basis over the lease term, which varies from the actual cash amount paid.*

Detailed Operating Results
Total NERC (including CRISP) as of September 30, 2017

Variances by Revenue and Expense Category

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 56,158,106**	**$ 54,636,357**	**$ 1,521,749**	**2.8%**	**$ 70,893,170**	**$ 70,151,660**	**$ 741,509**	**1.1%**
EXPENDITURES								
Personnel	$ 29,490,646	$ 29,298,089	$ 192,557	0.7%	$ 38,646,071	$ 38,641,331	$ 4,739	0.0%
Meetings, Travel & Conference Calls	2,614,590	2,529,665	84,925	3.4%	3,513,682	3,372,886	140,796	4.2%
Consultants & Contracts	8,918,080	9,921,024	(1,002,944)	-10.1%	14,453,379	13,127,749	1,325,630	10.1%
Office Costs, Professional and Misc.	4,914,019	5,147,081	(233,063)	-4.5%	6,878,337	6,864,475	13,862	0.2%
Fixed Asset Additions	1,222,031	3,279,000	(2,056,969)	-62.7%	3,304,896	4,372,000	(1,067,104)	-24.4%
TOTAL EXPENDITURES	**$ 49,352,496**	**$ 52,592,660**	**$ (3,240,164)**	**-6.2%**	**$ 69,885,788**	**$ 69,602,175**	**$ 283,613**	**0.4%**
RESERVE INCREASE (DECREASE)	**$ 6,805,611**	**$ 2,043,697**	**$ 4,761,914**	**233.0%**	**$ 1,007,381**	**$ 549,485**	**$ 457,896**	**83.3%**
FTEs	**190.4**	**189.9**	**0.5**	**0.3%**	**188.1**	**189.9**	**(1.8)**	**-1.0%**

Following is a brief summary of variances by major categories:

- Total Funding – Exceeds budget primarily due to additional CRISP participant funding, and $400k use of reserves

- Consultants and Contracts – Projected to be over budget at year-end:
  - Additional PNNL costs for CRISP (new participant start-up costs, security review)
  - E-ISAC portal improvement project – budgeted as custom development project in fixed assets, project is utilizing licensed software with costs recognized here
  - System operator certification (SOCCED) database replacement project
  - Additional outside support in IT

  Budget variances in Consultants and Contracts are substantially offset by additional CRISP participant funding and lower spending in Fixed Assets. Department detail is provided below.

CONSULTANTS and CONTRACTS	YTD Actual	YTD Budget	YTD Variance Over (Under)	Annual Projection	Annual Budget	Annual Variance Over (Under)
STANDARDS	$ 13,268	$ -	$ 13,268	$ 60,000	$ -	$ 60,000
COMPLIANCE ASSURANCE	750	37,500	(36,750)	35,800	50,000	(14,200)
REL. ASSESSMENTS and SYSTEM ANALYSIS	75,651	393,750	(318,099)	418,025	525,000	(106,975)
RELIABILITY RISK MANAGEMENT	1,354,105	1,443,162	(89,057)	1,866,982	1,823,932	43,049
E-ISAC	492,994	674,876	(181,882)	1,249,177	899,835	349,342
TRAINING, ED. & OP. CERTIFICATION	410,116	435,450	(25,334)	769,700	580,600	189,100
POLICY and EXTERNAL AFFAIRS	3,732	11,250	(7,518)	15,000	15,000	-
INFORMATION TECHNOLOGY	1,535,740	1,734,591	(198,850)	2,311,242	2,312,787	(1,545)
HUMAN RESOURCES	160,263	431,250	(270,987)	575,000	575,000	-
FINANCE and ACCOUNTING	84,567	342,750	(258,183)	399,001	457,000	(57,999)
TOTAL (excluding CRISP)	**$ 4,131,185**	**$ 5,504,578**	**$ (1,373,394)**	**$ 7,699,926**	**$ 7,239,155**	**$ 460,771**
CRISP	4,786,895	4,416,446	370,450	6,753,453	5,888,594	864,859
TOTAL CONTRACTS and CONSULTANTS	**$ 8,918,080**	**$ 9,921,024**	**$ (1,002,944)**	**$ 14,453,379**	**$ 13,127,749**	**$ 1,325,630**

- Office costs, professional services and miscellaneous – Projected to be over budget at year-end, primarily due to the expense treatment of the audio/video lease agreement. This variance is partially offset by lower spending in Fixed Assets, and lower spending on professional services and legal fees.

- Fixed Asset Additions (excluding depreciation) – Under budget primarily due to the accounting treatment of software projects and the A/V lease.

Variances by Department / Program

DIRECT EXPENSES and NET FIXED ASSETS	2017 Actual	2017 Budget	Variance Over/(Under)	2017 Projection	2017 Budget	Variance Over/(Under)
RELIABILITY STANDARDS	$ 2,468,699	$ 2,745,375	$ (276,676)	$ 3,325,132	$ 3,629,945	$ (304,813)
COMPLIANCE ANALYSIS, CERT. and REG.	1,819,339	1,278,294	541,045	2,603,870	1,686,689	917,181
COMPLIANCE ASSURANCE	3,046,793	2,888,870	157,922	4,129,854	3,816,924	312,930
ENFORCEMENT	1,838,631	1,794,211	44,420	2,391,507	2,371,347	20,159
REL. ASSESSMENTS and SYSTEM ANALYSIS	2,620,356	2,916,253	(295,897)	3,727,350	3,861,344	(133,995)
RELIABILITY RISK MANAGEMENT	6,196,953	5,762,850	434,103	8,035,549	7,529,324	506,225
E-ISAC	3,753,934	4,383,698	(629,765)	5,791,572	5,813,801	(22,229)
TRAINIING, ED. and OP. CERTIFICATION	1,293,075	1,448,497	(155,422)	1,923,756	1,920,376	3,380
GENERAL, ADMINISTRATIVE, and EXECUTIVE	5,796,786	6,145,980	(349,194)	7,775,192	8,171,444	(396,252)
POLICY and EXTERNAL AFFAIRS	1,731,694	1,539,285	192,409	2,273,081	2,034,533	238,548
LEGAL and REGULATORY	1,978,836	2,490,937	(512,101)	2,743,233	3,292,379	(549,146)
INFORMATION TECHNOLOGY	7,506,106	9,392,284	(1,886,177)	11,511,535	12,480,846	(969,311)
HUMAN RESOURCES	847,997	1,210,067	(362,070)	1,541,732	1,608,583	(66,850)
FINANCE and ACCOUNTING	2,921,793	2,922,456	(664)	4,056,050	3,827,050	229,000
TOTAL (excluding CRISP)	**$ 43,820,992**	**$ 46,919,059**	**$ (3,098,067)**	**$ 61,829,412**	**$ 62,044,585**	**$ (215,173)**
CRISP	5,531,504	5,673,601	(142,097)	8,056,376	7,557,591	498,786
TOTAL EXPENSES and FIXED ASSETS	**$ 49,352,496**	**$ 52,592,660**	**$ (3,240,164)**	**$ 69,885,788**	**$ 69,602,175**	**$ 283,613**

Following is a brief summary of significant variances (over $500k):

- Compliance Analysis, Certification and Registration
  - Additional resources added to support ongoing program activities
  - ERO Entity Registration project, transferred from IT ($479k)

- Reliability Risk Management
  - ERO software projects MIDAS and FERC 854, transferred from IT ($463k)

- Legal and Regulatory
  - Lower personnel costs
  - Lower professional services costs (offset by higher costs in Policy and External Affairs)

- Information Technology
  - Under budget primarily due to the transfer of certain ERO development projects, budgeted in IT but recognized in the relevant program area

SUPPLEMENTAL SCHEDULE 1

NERC Operating Reserves
2017 Year-end Projections
As of September 30, 2017

	Beginning Balance	Budgeted Funding	Budgeted Uses	Other Funding (Uses)	Net Financing Activity	Expected Ending Balance
Operating Contingency Reserve (OCR)	$ 2,307,531	$ 600,000	$ -	$ 450,911	$ 247,145	$ 3,605,587
Future Obligations Reserve (FOR)	2,875,467	-	(400,370)	(114,145)	-	2,360,952
Assessment Stabilization Reserve (ASR)	2,271,000	-	(1,100,000)	500,000	-	1,671,000
System Operator Reserves	828,013	-	-	(246,532)	-	581,481
CRISP	500,000	-	-	-	-	500,000
Total Reserves	$ 8,782,011	$ 600,000	$ (1,500,370)	$ 590,234	$ 247,145	$ 8,719,020

SUPPLEMENTAL SCHEDULE 2

NERC IT Projects
2017 Summary
Actuals through September 2017

Projects in Progress	Project Budget [1]	YTD Spend	Expected Spend	Expected Over (Under) Budget
Document Management	$ 2,211,000	$ 2,113,326	$ 2,246,325	$ 35,325
E-ISAC Portal	555,000	200,114	555,000	-
CMEP Program - Discovery	280,000	50,000	280,000	-
ERO Portal - MIDAS	174,725	174,725	174,725	-
NERC.com Phase 2	300,000	126,350	218,600	(81,400)
Entity Registration	600,000	211,677	507,035	(92,965)
SOCCED Replacement [2]	225,000	139,134	293,900	68,900

Projects Completed in 2017	Project Budget [1]	Actual Spend	Actual Over (Under) Budget
BESnet	$ 111,145	$ 111,145	$ -
GADS Wind	142,110	138,515	(3,595)
User Management and Registration (UMR)	569,279	572,601	3,322
Standards Balloting System	125,000	125,000	-
Enterprise Reporting - GADS	500,000	497,589	(2,411)

NOTES:

(1) The Project Budget noted above usually corresponds to the approved business case for each project and funds for each project are drawn from the available budget. In some projects, business cases may not be prepared, particularly when a project is smaller and/or may be in response to a FERC order.

(2) The SOCCED project overage is being funded by PCGC reserves.

** Some of these projects span multiple years, so the amounts above do not represent a single budget year expenditure.*

** The amounts noted above do not include internal labor and reflect only external (consultant) costs of the projects.*

SUPPLEMENTAL SCHEDULE 2
(continued)

Document Management
(Started Aug 2015 / Planned Completion Nov 2017)
NERC launched the Document Management Program to provide a secure and efficient method of creating, collaborating, storing and disseminating the vast amount of information produced at NERC.

E-ISAC Portal
(Started Mar 2017 / Planned Completion Mar 2018)
A replacement of the current portal platform with a more feature-rich content management solution (CMS), which could flex, grow, and change per the needs of the E-ISAC and sector over time.

CMEP - Discovery
(Started Apr 2017 / Planned Completion Dec 2020)
This initial phase of the CMEP Technology Project aims to discover the high-level business and technical requirements needed to launch an ERO Enterprise-wide CMEP tool, and to conduct a rigorous vendor selection for the tool itself. This discovery will transition into the full scope project expected over the next three years.

ERO Portal-MIDAS
(Started Jan 2017 / Planned Completion Dec 2017)
The ERO Portal Misoperations Information Data Analysis System (MIDAS) project enhanced the secure access point to the MIDAS application for Functional Entities (FEs). New functionality will allow the FEs more flexibility in managing their Misoperations data, while enhancing security through integration with the new User Management and Records account management system.

NERC.com Phase 2
(Started May 2017 / Planned Completion Dec 2017)
In response to feedback from stakeholders, this project is a first step to improve the usability and search capability of the public NERC.com website. The project will also enhance the stability of the NERC.com platform with a technology upgrade from SharePoint 2010 to SharePoint 2016 in Azure.

Entity Registration
(Started Jan 2017 / Planned Completion Dec 2017)
This first project addresses Consolidated Functional Registration (CFRs). Currently, this is a manual process using email and spreadsheets to request, approve and track CFRs. NERC IT leveraged the xRM platform (used for many other enterprise applications) to create an interface by which registered entities and Regions may request and track CFRs.

SOCCED Replacement
(Started Oct 2016 / Planned Completion Dec 2017)
This project will replace the current SOCCED credential management tool to enhance reliability and improve ease of maintenance.

SUPPLEMENTAL SCHEDULE 2
(continued)

BESnet
(Started Oct 2016 / Completed Mar 2017)
This provided enhancements to the existing BESnet application launched in 2014. Those enhancements included various user interface updates and automatic process notifications.

GADS Wind
(Started Jun 2016 / Completed Jun 2017)
The Generating Availability Data System (GADS) Wind Data Capture and Reporting project enabled consistent and reliable submission, processing, and reporting of wind generation data from Registered Entities to NERC for reliability and performance analysis.

User Management and Registration (UMR)
(Started Jan 2016 / Completed Jun 2017)
This project consolidated three legacy applications and their functions (User Management Program, NERC MyAccount and AppBroker) into the xRM platform. The result is one core identification and authentication system to manage access to NERC online resources. The project also provided the foundation for the xRM portal, by which stakeholders can access their authorized applications via one interface and single sign-on.

Standards Balloting System (SBS)
(Started Jul 2016 / Completed Feb 2017)
This 4th release of SBS addressed several business enhancements that included user interface updates, social survey access, sorting and filtering capability, and the ability to provide comments.

Enterprise Reporting: GADS
(Started Jun 2016 / Completed Feb 2017)
This project is the second installment of the Enterprise Reporting-Data Warehouse program, to include the loading of GADS data into the data warehouse. In future installments, the data warehouse will include data from other areas and be "connected" to each other via common fields. That will enable analytics across the enterprise not available today.

SUPPLEMENTAL SCHEDULE 3

NERC E-ISAC and CRISP
2017 Summary of Activites
As of September 30, 2017

TOTAL E-ISAC (including CRISP)

	YTD Actual	Year-end Projection	Budget	Projected Over (Under)
Assessments	$ 8,453,029	$ 11,270,705	$ 11,270,705	$ -
Other Funding	8,451,658	7,718,351	7,244,636	473,715
Total Funding	$ 16,904,687	$ 18,989,056	$ 18,515,341	$ 473,715
Personnel Expenses	$ 3,403,601	$ 4,528,427	$ 4,382,370	$ 146,057
Meeting Expense	271,911	448,562	493,198	(44,636)
Operating Expenses, excluding Depreciation	5,482,450	8,406,988	7,395,824	1,011,164
Fixed Assets, including Allocations	(32,787)	463,044	1,433,765	(970,721)
Indirect Expenses	3,623,279	5,035,021	4,810,185	224,836
Total Expenditures	$ 12,748,454	$ 18,882,042	$ 18,515,341	$ 366,701
Net Position	$ 4,156,233	$ 107,014	$ -	$ 107,014

SUPPLEMENTAL SCHEDULE 3
(continued)

CRISP only

	YTD Actual	Year-end Projection	Budget	Projected Over (Under)
Assessments	$ 956,760	$ 1,275,681	$ 1,275,681	$ -
Other Funding	8,282,514	7,475,311	7,016,760	458,552
Total Funding	$ 9,239,275	$ 8,750,992	$ 8,292,441	$ 458,551
Personnel Expenses	$ 566,451	$ 742,050	$ 768,371	$ (26,321)
Meeting Expense	23,777	68,303	69,692	(1,389)
Operating Expenses, excluding Depreciation	4,893,300	7,037,710	6,369,527	668,183
Fixed Assets, including Allocations	26,040	208,185	397,681	(189,496)
Indirect Expenses	495,949	694,743	687,169	7,574
Total Expenditures	$ 6,005,516	$ 8,750,992	$ 8,292,441	$ 458,551
Net Position	$ 3,233,759	$ -	$ -	$ -

E-ISAC (without CRISP)

	YTD Actual	Year-end Projection	Budget	Projected Over (Under)
Assessments	$ 7,496,268	$ 9,995,024	$ 9,995,024	$ -
Other Funding	169,144	243,040	227,876	15,164
Total Funding	$ 7,665,412	$ 10,238,064	$ 10,222,900	$ 15,164
Personnel Expenses	$ 2,837,150	$ 3,786,377	$ 3,613,999	$ 172,378
Meeting Expense	248,134	380,259	423,505	(43,247)
Operating Expenses, excluding Depreciation	589,150	1,369,279	1,026,297	342,982
Fixed Assets, including Allocations	(58,827)	254,859	1,036,084	(781,225)
Indirect Expenses	3,127,331	4,340,277	4,123,015	217,262
Total Expenditures	$ 6,742,938	$ 10,131,050	$ 10,222,900	$ (91,850)
Net Position	$ 922,474	$ 107,014	$ -	$ 107,014

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC
Summary of Unaudited Results
September 30, 2017

Scott Jones, Vice President and Chief Financial and Administrative Officer
Finance and Audit Committee Meeting
November 8, 2017

RELIABILITY | ACCOUNTABILITY

Third Quarter 2017 Significant Variances

- NERC was 2.8% over budget in total funding
  - Primarily due to additional funding for new CRISP members
- NERC was 6.2% under budget in total expenditures (including cap-ex)
  - Personnel costs are very close to budget
  - Contracts/Consultants and Cap-Ex are currently well under budget

2017 Year-End Projections

- NERC is projecting 1.1% over budget in total funding
  - Primarily due to additional funding for new CRISP members
- NERC is projecting 0.4% over budget in total expenditures (including cap-ex)
  - Personnel is projected to be almost exactly on budget
  - Additional costs related to new CRISP members
  - Remaining increases in contracts/consultants are largely offset by decreases in cap-ex
- Net impact of funding, expenditures, and reserves is an increase in operating reserves (above budget) of $458k

2017 Year-End Working Capital and Operating Reserve Projections

- System Operator Reserve - $581k
- CRISP Reserve - $500k
- Assessment Stabilization Reserve - $1.7M
- Future Obligation Reserve - $2.4M
- Operating Contingency Reserve - $3.6M
  - Over budget projection implies reduction of operating reserves
  - Other factors impact reserves as well (financing proceeds, non-cash expenses, other reserve funding)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Questions and Answers

20171016-3021 FERC PDF (Unofficial) 10/16/2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD17-8-000

October 16, 2017

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation and ReliabilityFirst Corporation for Approval of Proposed Regional Reliability Standard BAL-502-RF-03

Dear Mr. Elstein:

On September 7, 2017, the North American Electric Reliability Corporation (NERC) and ReliabilityFirst Corporation (ReliabilityFirst) filed a joint petition seeking approval of proposed regional Reliability Standard BAL-502-RF-03 (Planning Resource Adequacy Analysis, Assessment and Documentation). NERC and ReliabilityFirst also requested approval of the associated implementation plan for the proposed regional Reliability Standard, violation risk factors and violation severity levels, and retirement of regional Reliability Standard BAL-502-RFC-02. The proposed regional Reliability Standard BAL-502-RF-03 establishes common criteria, based on "one day in ten year" loss of load expectation principles, for the analysis, assessment, and documentation of resource adequacy for load in the ReliabilityFirst region.[1]

Proposed regional Reliability Standard BAL-502-RF-03 addresses Commission directives to: (1) add time horizons applicable to the requirements; and (2) consider including a requirement that the planning coordinators identify any gap between the

[1] Petition at 1.

20171016-3021 FERC PDF (Unofficial) 10/16/2017

needed amount of planning reserves and the documented projected planning reserves determined from the resource adequacy analysis.[2]

NERC and ReliabilityFirst's filing was noticed on September 8, 2017, with interventions, comments and protests due on or before October 10, 2017. No comments were received.

NERC and ReliabilityFirst's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2017), effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2017).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[2] *Id.* at 6-7 (citing *Planning Resource Adequacy Assessment Reliability Standard*, Order No. 747, 134 FERC ¶ 61,212, at PP 53, 65 (2011)).

Document Content(s)

RD17-8-000.DOCX.....1-2

20171016-3022 FERC PDF (Unofficial) 10/16/2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD17-9-000

October 16, 2017

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Senior Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation and SERC Reliability Corporation for Approval of Proposed Regional Reliability Standard PRC-006-SERC-02

Dear Mr. Elstein:

On September 8, 2017, the North American Electric Reliability Corporation (NERC) and SERC Reliability Corporation (SERC) filed a joint petition seeking approval of proposed regional Reliability Standard PRC-006-SERC-02 (Automatic Underfrequency Load Shedding (UFLS) Requirements). NERC and SERC also requested approval of the associated effective date for the proposed regional Reliability Standard, violation risk factors and violation severity levels, and retirement of regional Reliability Standard PRC-006-SERC-01. Proposed regional Reliability Standard PRC-006-SERC-02 establishes consistent and coordinated requirements for the design, implementation, and analysis of automatic UFLS programs among all SERC applicable entities.[1]

Proposed regional Reliability Standard PRC-006-SERC-02 incorporates revisions that provide additional flexibility for planning coordinators to select the peak season for UFLS plans and additional clarity on the load that can be used for UFLS schemes in the SERC region. The proposed revisions resulted from a periodic review of regional

[1] Petition at 1.

20171016-3022 FERC PDF (Unofficial) 10/16/2017

Reliability Standard PRC-006-SERC-01.[2] In approving regional Reliability Standard PRC-006-SERC-01, the Commission stated that the regional Reliability Standard is "designed to work in conjunction with NERC Reliability Standard PRC-006-1 to mitigate the consequences of an underfrequency event effectively while accommodating differences in system transmission and distribution topology among SERC planning coordinators due to historical design criteria, makeup of load demands, and generation resources." Proposed regional Reliability Standard PRC-006-SERC-02 continues to satisfy these criteria.

NERC's filing was noticed on September 8, 2017, with interventions, comments and protests due on or before October 10, 2017. No comments were received.

NERC's uncontested filing is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2017), effective as of the date of this order.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.303(a)(2)(i). Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order, pursuant to 18 C.F.R. § 385.713 (2017).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[2] *Id.* at 2.

Document Content(s)

RD17-9-000.DOCX.....1-2

20171027-3001 FERC PDF (Unofficial) 10/27/2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability
Corporation
Docket No. RR17-5-000

October 27, 2017

North American Electric Reliability Corporation
1325 G Street, NW, Suite 600
Washington, DC 20005

Attention: Marisa Hecht
Counsel for North American Electric Reliability Corporation

Reference: Amended Regional Reliability Standards Development Procedure

Dear Ms. Hecht:

On June 8, 2017, North American Electric Reliability Corporation (NERC) submitted amendments to the Western Electricity Coordinating Council Regional Reliability Standards Development Procedures.

Notice of this filing was issued on June 8, 2017, with protests and interventions due on or before June 29, 2017. Notices of intervention and unopposed timely filed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure. 18 C.F.R. § 385.214. No protest was filed.

NERC's uncontested filing is accepted pursuant to the relevant authority delegated to the Director, Office of Energy Market Regulation, under 18 C.F.R. § 375.307.

This action shall not be construed as approving any other application, including proposed revisions of Electric Reliability Organization or Regional Entity rules or procedures pursuant to 18 C.F.R. § 375.307(a)(2)(vi). This action does not constitute approval of any service, rate, charge, classification, or any rule, regulation, contract, or practice affecting such rate or service provided for in the filed documents. Such action shall not be deemed as recognition of any claimed right or obligation associated therewith and such action is without prejudice to any findings or orders that have been or may

20171027-3001 FERC PDF (Unofficial) 10/27/2017

hereafter be made by the Commission in any proceeding now pending or hereafter instituted by or against the Electric Reliability Organization or any Regional Entity.

This order constitutes final agency action. Requests for rehearing by the Commission may be filed within 30 days of the date of issuance of this order pursuant to 18 C.F.R. § 385.713.

Sincerely,

Penny S. Murrell, Director
Division of Electric Power Regulation – Central

Document Content(s)

RR17-5-000.DOCX.....1-2

161 FERC ¶ 61,047
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM17-11-000]

Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls

(Issued October 19, 2017)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to approve Critical Infrastructure Protection (CIP) Reliability Standard CIP-003-7 (Cyber Security – Security Management Controls), submitted by the North American Electric Reliability Corporation (NERC). Proposed Reliability Standard CIP-003-7 improves upon the current Commission-approved CIP Reliability Standards by clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. In addition, the Commission proposes to direct NERC to develop certain modifications to the NERC Reliability Standards to provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems;

and address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices.

DATES: Comments are due **[INSERT DATE 60 days after publication in the FEDERAL REGISTER].**

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

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

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

FOR FURTHER INFORMATION CONTACT:

Matthew Dale (Technical Information)
Office of Electric Reliability
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426
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matthew.dale@ferc.gov

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Revised Critical Infrastructure Protection Reliability Standard CIP-003-7 – Cyber Security – Security Management Controls	Docket No. RM17-11-000

NOTICE OF PROPOSED RULEMAKING

(Issued October 19, 2017)

1. Pursuant to section 215 of the Federal Power Act (FPA),[1] the Commission proposes to approve Critical Infrastructure Protection (CIP) Reliability Standard CIP-003-7 (Cyber Security – Security Management Controls). The North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO), submitted proposed Reliability Standard CIP-003-7 in response to directives in Order No. 822.[2] The Commission also proposes to approve the associated violation risk factors and violation severity levels, implementation plan and effective dates proposed by NERC. In addition, the Commission proposes to approve the modified definitions of Transient Cyber Asset and Removable Media as well as the retirement of the definitions for Low Impact External Routable Connectivity (LERC) and Low Impact Electronic Access Point (LEAP) in the NERC Glossary of Terms Used in NERC

[1] 16 U.S.C. 824o (2012).

[2] *Revised Critical Infrastructure Protection Reliability Standards*, Order No. 822, 154 FERC ¶ 61,037, *reh'g denied*, Order No. 822-A, 156 FERC ¶ 61,052 (2016).

Reliability Standards (NERC Glossary). Further, the Commission proposes to approve the retirement of Reliability Standard CIP-003-6.

2. Proposed Reliability Standard CIP-003-7 is designed to mitigate the cybersecurity risks to bulk electric system facilities, systems, and equipment, which, if destroyed, degraded, or otherwise rendered unavailable as a result of a cybersecurity incident, would affect the reliable operation of the bulk electric system.[3] As discussed below, the Commission proposes to determine that proposed Reliability Standard CIP-003-7 is just, reasonable, not unduly discriminatory or preferential, and in the public interest and addresses the directives in Order No. 822 by: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems;[4] and (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems. In addition, by requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances for low impact BES Cyber Systems, the proposed Reliability Standard aligns the treatment of low impact BES Cyber Systems with that of high and medium impact BES Cyber Systems, which currently include a requirement for declaring and responding to CIP Exceptional Circumstances. Accordingly, we propose to approve proposed

[3] *See* NERC Petition at 2.

[4] NERC defines "BES Cyber System" as one or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.

Reliability Standard CIP-003-7 because the proposed modifications improve the base-line cybersecurity posture of responsible entities compared to the current Commission-approved CIP Reliability Standards.

3. In addition, pursuant to FPA section 215(d)(5), the Commission proposes to direct NERC to develop certain modifications to the CIP Reliability Standards. As discussed below, while proposed Reliability Standard CIP-003-7 improves electronic access control for low impact BES Cyber Systems and enhances security controls for transient electronic devices used at low impact BES Cyber Systems, we propose to direct that NERC modify Reliability Standard CIP-003-7 to: (1) provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems; and (2) address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices. We believe that modifications addressing these two concerns will address potential gaps and improve the cyber security posture of responsible entities that must comply with the CIP standards.

I. Background

A. Section 215 and Mandatory Reliability Standards

4. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval. Reliability Standards may be enforced by the ERO, subject to Commission

oversight, or by the Commission independently.[5] Pursuant to section 215 of the FPA, the Commission established a process to select and certify an ERO,[6] and subsequently certified NERC.[7]

B. Order No. 822

5. The Commission approved the "Version 1" CIP standards in January 2008, and subsequently acted on revised versions of the CIP standards.[8] On January 21, 2016, in Order No. 822, the Commission approved seven CIP Reliability Standards: CIP-003-6 (Security Management Controls), CIP-004-6 (Personnel and Training), CIP-006-6 (Physical Security of BES Cyber Systems), CIP-007-6 (Systems Security Management), CIP-009-6 (Recovery Plans for BES Cyber Systems), CIP-010-2 (Configuration Change Management and Vulnerability Assessments), and CIP-011-2 (Information Protection). The Commission determined that the Reliability Standards under consideration at that time were an improvement over the prior iteration of the CIP Reliability Standards and

[5] 16 U.S.C. 824o(e) (2012).

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

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

[8] *Mandatory Reliability Standards for Critical Infrastructure Protection*, Order No. 706, 122 FERC ¶ 61,040, *order on reh'g*, Order No. 706-A, 123 FERC ¶ 61,174 (2008), *order on clarification*, Order No. 706-B, 126 FERC ¶ 61,229 (2009), *order on clarification*, Order No. 706-C, 127 FERC ¶ 61,273 (2009).

addressed the directives in Order No. 791 by, among other things, addressing in an equally effective and efficient manner the need for a NERC Glossary definition for the term "communication networks" and providing controls to address the risks posed by transient electronic devices (e.g., thumb drives and laptop computers) used at high and medium impact BES Cyber Systems.[9]

6. In addition, in Order No. 822, pursuant to section 215(d)(5) of the FPA, the Commission directed NERC, *inter alia*, to: (1) develop modifications to the LERC definition to eliminate ambiguity surrounding the term "direct" as it is used in the LERC definition; and (2) develop modifications to the CIP Reliability Standards to provide mandatory protection for transient electronic devices used at low impact BES Cyber Systems.[10]

C. NERC Petition

7. On March 3, 2017, NERC submitted a petition seeking approval of Reliability Standard CIP-003-7 and the associated violation risk factors and violation severity levels, implementation plan and effective dates. NERC states that proposed Reliability Standard CIP-003-7 satisfies the criteria set forth in Order No. 672 that the Commission applies when reviewing a proposed Reliability Standard.[11] NERC also sought approval of

[9] Order No. 822, 154 FERC ¶ 61,037 at P 17; *see also Version 5 Critical Infrastructure Protection Reliability Standards*, Order No. 791, 78 Fed. Reg. 72,755 (Dec. 3, 2013), 145 FERC ¶ 61,160 (2013), *order on clarification and reh'g*, Order No. 791-A, 146 FERC ¶ 61,188 (2014).

[10] Order No. 822, 154 FERC ¶ 61,037 at P 18.

[11] *See* NERC Petition at 2 (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204 at PP 262, 321-337); *id.* at Exhibit D (Order No. 672 Criteria).

revisions to NERC Glossary definitions for the terms Removable Media and Transient Cyber Asset, as well as the retirement of the NERC Glossary definitions of LERC and LEAP. In addition, NERC proposed the retirement of Commission-approved Reliability Standard CIP-003-6.

8. NERC states that proposed Reliability Standard CIP-003-7 improves upon the existing protections that apply to low impact BES Cyber Systems. NERC avers that the proposed modifications address the Commission's directives from Order No. 822 by: (1) clarifying electronic access control requirements applicable to low impact BES Cyber Systems; and (2) adding requirements for the protection of transient electronic devices used for low impact BES Cyber Systems. In addition, while not required by Order No. 822, NERC proposes a CIP Exceptional Circumstances policy for low impact BES Cyber Systems.

9. In response to the Commission's directive to develop modifications to eliminate ambiguity surrounding the term "direct" as it is used in the LERC definition, NERC proposes to: (1) retire the terms LERC and LEAP from the NERC Glossary; and (2) modify Section 3 of Attachment 1 to proposed Reliability Standard CIP-003-7 "to more clearly delineate the circumstances under which Responsible Entities must establish access controls for low impact BES Cyber Systems."[12] NERC states that the proposed revisions are designed to simplify the electronic access control requirements associated with low impact BES Cyber Systems in order to avoid ambiguities associated with the

[12] *Id.* at 16.

term "direct." NERC explains that it recognized the "added layer of unnecessary complexity" introduced by distinguishing between "direct" and "indirect" access within the LERC definition and asserts that the proposed revisions will "help ensure that Responsible Entities implement the required security controls effectively."[13]

10. With regard to the Commission's directive to develop modifications to the CIP Reliability Standards to provide mandatory protection for transient electronic devices used at low impact BES Cyber Systems, NERC proposes to add a new section to Attachment 1 to proposed Reliability Standard CIP-003-7 to require responsible entities to include controls in their cyber security plans to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems that could result from the use of "Transient Cyber Assets or Removable Media." Specifically, proposed Section 5 of Attachment 1 lists controls to be applied to Transient Cyber Assets and Removable Media that NERC contends "will provide enhanced protections against the propagation of malware from transient devices."[14]

11. NERC also proposes a modification that was not directed by the Commission in Order No. 822. Namely, NERC proposes revisions in Requirement R1 of proposed Reliability Standard CIP-003-7 to require responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES

[13] *Id.* at 16.

[14] *Id.* at 26-27.

Cyber Systems.[15] NERC states that a number of requirements in the existing CIP Reliability Standards specify that responsible entities do not have to implement or continue implementing these requirements during a CIP Exceptional Circumstance in order to avoid hindering the entities' ability to timely and effectively respond to the CIP Exceptional Circumstance. NERC explains that since the proposed requirements relating to transient electronic devices used at low impact BES Cyber Systems include an exception for CIP Exceptional Circumstances, NERC is proposing to add a requirement for responsible entities to have a CIP Exceptional Circumstances policy that applies to low impact BES Cyber Systems, as it already requires for high and medium impact BES Cyber Systems.[16]

12. NERC requests that proposed Reliability Standard CIP-003-7 and the revised definitions of Transient Cyber Asset and Removable Media become effective the first day of the first calendar quarter that is eighteen months after the effective date of the Commission's order approving the proposed Reliability Standard.

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[15] A CIP Exceptional Circumstance is defined in the NERC Glossary as a situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or bulk electric system reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability. Glossary of Terms Used in NERC Reliability Standards (August 1, 2017), http://www.nerc.com/files/glossary_of_terms.pdf.

[16] NERC Petition at 31-32.

II. Discussion

13. Pursuant to section 215(d)(2) of the FPA, we propose to approve Reliability Standard CIP-003-7 as just, reasonable, not unduly discriminatory or preferential, and in the public interest. Proposed Reliability Standard CIP-003-7 largely addresses the Commission's directives in Order No. 822 and is an improvement over the current Commission-approved CIP Reliability Standards. Specifically, the modifications to Section 3 of Attachment 1 to Reliability Standard CIP-003-7 clarify the obligations pertaining to electronic access control for low impact BES Cyber Systems. In addition, the modifications to Attachment 1 to Reliability Standard CIP-003-7 require mandatory security controls for transient electronic devices used at low impact BES Cyber Systems. We also propose to approve the new provision in Reliability Standard CIP-003-7, Requirement R1 requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems. While Order No. 822 did not direct NERC to expand the scope of the CIP Exceptional Circumstances policy, the revision aligns the treatment of low impact BES Cyber Systems with that of high and medium impact BES Cyber Systems if and when a CIP Exceptional Circumstance occurs.

14. We also propose to approve the revisions to the NERC Glossary definitions of Transient Cyber Asset and Removable Media, as well as the retirement of the NERC Glossary definitions for LERC and LEAP since the proposed modifications to Reliability Standard CIP-003-7 obviate the need for the two terms. We further propose to approve the violation risk factor and violation severity level assignments associated with proposed

Reliability Standard CIP-003-7 as well as NERC's proposed implementation plan and effective dates.

15. In addition, as discussed below, pursuant to section 215(d)(5) of the FPA, the Commission proposes to direct NERC to develop certain modifications to the CIP Reliability Standards. While proposed Reliability Standard CIP-003-7 improves electronic access control for low impact BES Cyber Systems and enhances security controls for transient electronic devices used at low impact BES Cyber Systems, we propose to direct that NERC modify Reliability Standard CIP-003-7 to: (1) provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems; and (2) address the need to mitigate the risk of malicious code that could result from third-party transient electronic devices.

16. Below, we discuss the following issues: (A) electronic access controls for low impact BES Cyber Systems; (B) protection of transient electronic devices; (C) proposed retirement and modification of definitions; (D) NERC's proposed implementation plan and effective dates; and (E) proposed violation severity level and violation risk factor assignments.

A. Electronic Access Controls for Low Impact BES Cyber Systems

Order No. 822

17. In Order No. 822, the Commission directed NERC to modify the LERC definition to eliminate ambiguity surrounding the term "direct" as it is used in the LERC

definition.[17] The Commission explained that the directive was intended to codify the clarification provided in NERC's NOPR comments, in which NERC referenced a statement in the Guidelines and Technical Basis section of Reliability Standard CIP-003-6 that electronic access controls must be applied to low impact BES Cyber Systems unless responsible entities implement a "complete security break" between the external host (cyber asset) and any cyber asset(s) that may be used to pass communications to the low impact BES Cyber System.[18] The Commission observed that "a suitable means to address our concern is to modify the [LERC] definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6."[19]

18. In addition, the Commission explained that the directive was also intended to eliminate a loophole that would have allowed transitive connections to out-of-scope cyber assets (e.g., serial devices) to go unprotected under the LERC definition.[20]

NERC Petition

19. In its Petition, NERC proposes to: (1) retire the terms LERC and LEAP from the NERC Glossary; and (2) modify Section 3 of Attachment 1 to Reliability Standard

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[17] Order No. 822, 154 FERC ¶ 61,037 at P 73.

[18] *Id.* (citing NERC NOPR Comments at 31).

[19] *Id.*

[20] *Id.* ("NERC's clarification on this issue resolves many of the concerns raised by EnergySec, APS, and SPP RE regarding the proposed definition, as a complete security break would not appear to permit transitive connections through one or more out of scope cyber assets to go unprotected under the definition, and would appear to require the assets to maintain 'separate conversations' as suggested by SPP RE.").

CIP-003-7 "to more clearly delineate the circumstances under which Responsible Entities must establish access controls for low impact BES Cyber Systems."[21] NERC states that the proposed revisions are designed to simplify the electronic access control requirements associated with low impact BES Cyber Systems in order to avoid ambiguities associated with the term "direct." NERC states further that it recognized the "added layer of unnecessary complexity" introduced by distinguishing between "direct" and "indirect" access within the LERC definition and asserts that the proposed revisions will "help ensure that Responsible Entities implement the required security controls effectively."[22]

20. NERC states that proposed Reliability Standard CIP-003-7 would require responsible entities to implement electronic access controls for any communication, direct or indirect (i.e., communications through an intermediary device where no direct connection is present), between a low impact BES Cyber System and an outside Cyber Asset that uses a routable protocol when entering or leaving the asset containing the low impact BES Cyber System. NERC asserts that the proposed revisions to Section 3 of Attachment 1 to proposed Reliability Standard CIP-003-7 improve the clarity of the electronic access requirements and focus responsible entities "on the security objective of controlling electronic access to permit only necessary inbound and outbound electronic access to low impact BES Cyber Systems."[23]

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[21] NERC Petition at 16.

[22] *Id.*

[23] *Id.* at 17.

21. NERC explains that Section 3.1 of Attachment 1 to proposed Reliability Standard CIP-003-7 is composed of three basic elements: (1) identifying routable protocol communications from outside the asset containing the low impact BES Cyber System; (2) determining necessary inbound and outbound electronic access; and (3) implementing electronic access controls to permit only necessary inbound and outbound electronic access to the low impact BES Cyber System.

22. With regard to the first element, NERC states that Section 3.1 of Attachment 1 defines the circumstances where communications require electronic access controls. The three characteristics are:

> (1) the communication is between the low impact BES Cyber System and a Cyber Asset outside the asset containing low impact BES Cyber System(s);
> (2) the communication uses a routable protocol when entering or leaving the asset containing the low impact BES Cyber System(s); and
> (3) the communication is not used for time-sensitive protection or control functions between intelligent electronic devices.

NERC states further that each of the three characteristics were included in the original LERC definition.[24]

23. NERC asserts that the first characteristic helps to properly focus the electronic access controls in light of "the wide array of low impact BES Cyber Systems and the risk-based approach to protecting different types of BES Cyber Systems."[25] NERC explains that, whether a "Responsible Entity uses a logical border as a demarcation point

[24] *Id.* at 18.

[25] *Id.* at 19.

or some other understanding of what is inside or outside the asset, [the responsible entity] would have to provide a reasonable justification for its determination."[26] On the second characteristic, NERC states that routable communications present increased risks to the security of BES Cyber Systems and require additional protections. Therefore, communications with a low impact BES Cyber System involving routable connections require protections to address the risk of uncontrolled communications. With regard to the third characteristic, NERC explains that the exclusion of communications for time-sensitive protection and control functions is intended to avoid precluding the functionality of time-sensitive reliability enhancing functions. NERC states, however, that an entity invoking this exclusion may have to demonstrate that applying electronic access controls would introduce latency that would negatively impact functionality.[27]

24. According to NERC, the second characteristic of Section 3.1 of Attachment 1 provides that responsible entities may permit only necessary inbound and outbound electronic access to low impact BES Cyber Systems as determined by the responsible entity. NERC explains that Section 3.1 does not specify a bright line as to what constitutes "necessary inbound and outbound access" due to "the wide array of assets containing low impact BES Cyber Systems and the myriad of reasons a Responsible Entity may need to allow electronic access to and from a low impact BES Cyber

[26] *Id.*

[27] *Id.* at 20.

Systems."[28] NERC maintains that responsible entities "have the flexibility to identify the necessary electronic access to meet their business and operational needs."[29]

25. NERC explains that "a Responsible Entity must document the necessity of its inbound and outbound electronic access permissions and provide justification of the need for such access" in order to demonstrate compliance with Section 3.1 of Attachment 1.[30] NERC states that absent a documented, reasonable justification, the ERO may find that the responsible entity was not in compliance with Section 3.1. NERC asserts that the purpose of the phrase "as determined by the Responsible Entity" in Section 3.1 is to indicate that the determination whether electronic access is necessary is to be made in the first instance by the responsible entity based on the facts and circumstances of each case. NERC states further that that the phrase "as determined by the Responsible Entity" does not limit the ERO's ability to engage in effective compliance oversight. Specifically, NERC contends that the ERO has the authority to review the documented justification for permitting electronic access and to determine whether it represents a reasonable exercise of discretion in light of the overall reliability objective.[31]

[28] *Id.* at 21-22.

[29] *Id.* at 22.

[30] *Id.*

[31] *Id.* at 22-23.

26. In support of its position, NERC cites the draft Reliability Standard Audit Worksheet (RSAW) for proposed Reliability Standard CIP-003-7, which provides the following language in the Note to Auditor section for Requirement R2:

> The entity must document its determination as to what is necessary inbound and outbound electronic access and provide justification of the business need for such access. Once this determination has been made and documented, the audit team's professional judgment cannot override the determination made by the Responsible Entity.[32]

NERC also provides a list of Commission-approved CIP Reliability Standards where the phrase "as determined by the Responsible Entity" or similar language is used. NERC states that in all circumstances where the phrase "as determined by the Responsible Entity" or similar language is used, "the ERO has the authority to evaluate the reasonableness of the Responsible Entity's determination when assessing compliance to ensure it is consistent with the reliability objective of the requirement. To interpret this language otherwise would be inconsistent with NERC's statutory obligation to engage in meaningful compliance oversight…"[33]

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[32] *Id.* at 22, n.42.

[33] *Id.* at 23-24. NERC also indicates, *id* at n.42, that Footnote 1 of the draft RSAW states that "[w]hile the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in the RSAW, to determine compliance with the Reliability Standard." Draft RSAW, http://www.nerc.com/pa/Stand/Project%20201602%20Modifications%20to%20CIP%20Standards%20DL/RSAW_CIP-003-7(i)_v2_Clean_01202017.pdf.

Commission Proposal

27. The Commission proposes to approve Reliability Standard CIP-003-7 because, as discussed above, the proposed Reliability Standard largely addresses the directives in Order No. 822 and is an improvement over the current Commission-approved CIP Reliability Standards. However, NERC's proposed revisions to Reliability Standard CIP-003-7 regarding the LERC directive and electronic access controls for low impact BES Cyber Systems raise certain issues. In Order No. 822, the Commission directed NERC to develop modifications to the LERC definition to eliminate ambiguity surrounding the term "direct" as it is used in the definition. The directive was based on the concern that responsible entities could avoid adopting adequate electronic access protections for low impact BES Cyber Systems by simply installing a device, such as a laptop or protocol converter, in front of the BES Cyber System to "break" the direct routable connection. As the Commission noted in Order No. 822, the desired clarification could have been made by including the security concepts from the Guidelines and Technical Basis section of Reliability Standard CIP-003-6 in the definition.[34] Instead, NERC's proposal comprehensively revises a responsible entity's obligations under Requirement R2 through the revisions to Attachment 1 by deleting the

[34] *See* Order No. 822, 154 FERC ¶ 61,037 at P 73.

term LERC and giving responsible entities significantly more deference in determining how they construct the electronic access protections for low impact BES Cyber Systems.

28. We are concerned that the proposed revisions may not provide adequate electronic access controls for low impact BES Cyber Systems. Specifically, proposed Reliability Standard CIP-003-7 does not provide clear, objective criteria or measures to assess compliance by independently confirming that the access control strategy adopted by a responsible entity would reasonably meet the security objective of permitting only "necessary inbound and outbound electronic access" to its low impact BES Cyber Systems.

29. Section 3.1 of Attachment 1 to proposed Reliability Standard CIP-003-7 does not appear to contain clear criteria or objective measures to determine whether the electronic access control strategy chosen by the responsible entity would be effective for a given low impact BES Cyber System to permit only necessary inbound and outbound connections. In order to ensure an objective and consistently-applied requirement, the electronic access control plan required in Attachment 1 should require the responsible entity to articulate its access control strategy for a particular set of low impact BES Cyber Systems and provide a technical rationale rooted in security principles explaining how that strategy will reasonably restrict electronic access. Attachment 1 should also outline basic security principles in order to provide clear, objective criteria or measures to assist in assessing compliance. Without such a requirement, auditors will not necessarily have adequate information to assess the reasonableness of the responsible entity's decision with respect to how the responsible entity identified necessary communications or

restricted electronic access to specific low impact BES Cyber Systems. And absent such information, it is possible that an auditor could assess a violation where an entity adequately protected its low impact BES Cyber Systems or fail to recognize a situation where additional protections are necessary to meet the security objective of the standard.

30. As the Commission stated in Order No. 672, there "should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner."[35] The Commission reiterated this point in Order No. 791, stating that "the absence of objective criteria to evaluate the controls chosen by responsible entities for Low Impact assets introduces an unacceptable level of ambiguity and potential inconsistency into the compliance process, and creates an unnecessary gap in reliability."[36] The Commission also observed that "ambiguity will make it difficult for registered entities to develop, and NERC and the regions to objectively evaluate, the effectiveness of procedures developed to implement" the Reliability Standard.[37]

31. As a possible model, the electronic access control requirements that are applied to medium and high impact BES Cyber systems provide a number of criteria that can be used to assess the sufficiency of a responsible entity's electronic access control strategy.

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[35] *Rules Concerning Certification of the Electric Reliability Organization and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 327 (2006).

[36] Order No. 791, 145 FERC ¶ 61,160 at P 108.

[37] *Id.*

For medium and high impact BES Cyber Systems, auditors use the following criteria to review whether the access control strategy is reasonable: (1) whether the electronic access was granted through an authorized and monitored electronic access point (Reliability Standard CIP-005-5, Requirement R1); (2) whether the electronic access granted to individuals/devices was evaluated based on need (Reliability Standard CIP-005-5, Requirement R1.3); (3) whether the entity has mechanisms to enforce authentication of users with electronic access (Reliability Standard CIP-007-6, Requirement R5); and (4) whether the responsible entity routinely uses strong passwords and manages password changes (Reliability Standard CIP-007-6, Requirement R5). Absent similar criteria in the low impact electronic access control plan that are appropriately tailored to the risks posed by low impact BES Cyber Systems, responsible entities may adopt electronic access controls that do not meet the overarching security objective of restricting inbound and outbound electronic access.

32. Therefore, pursuant to section 215(d)(5) of the FPA, we propose to direct NERC to develop modifications to Reliability Standard CIP-003-7 to provide clear, objective criteria for electronic access controls for low impact BES Cyber Systems consistent with the above discussion. The Commission seeks comment on this proposal.

B. Protection of Transient Electronic Devices

Order No. 822

33. In Order No. 822, the Commission directed NERC to develop modifications to provide mandatory protection for transient electronic devices used at low impact BES Cyber Systems based on the risk posed to bulk electric system reliability. The

Commission stated that such modifications "will provide an important enhancement to the security posture of the bulk electric system by reinforcing the defense-in-depth nature of the CIP Reliability Standards at *all* impact levels."[38] The Commission also stated that the proposed modifications should be designed to effectively address the risks posed by transient electronic devices used at low impact BES Cyber Systems "in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards."[39]

NERC Petition

34. In its Petition, NERC proposes to add a new section to Attachment 1 to proposed Reliability Standard CIP-003-7 to require responsible entities to include controls in their cyber security plans to mitigate the risk of the introduction of malicious code to low impact BES Cyber Systems through the use of "Transient Cyber Assets or Removable Media." Specifically, proposed Section 5 of Attachment 1 lists controls to be applied to Transient Cyber Assets and Removable Media that NERC states "will provide enhanced protections against the propagation of malware from transient devices."[40]

35. NERC states that the language in proposed Section 5 to Attachment 1 parallels the language in Attachment 1 to Reliability Standard CIP-010-2, which addresses mitigation of the risks of the introduction of malicious code to high and medium impact BES Cyber Systems through the use of Transient Cyber Assets or Removable Media. NERC states further that, as in Reliability Standard CIP-010-2, proposed Section 5 distinguishes

[38] Order No. 822, 154 FERC ¶ 61,037 at P 32 (emphasis in original).

[39] *Id.*

[40] *Id.* at 26-27.

between Transient Cyber Assets managed by a responsible entity and those managed by a third-party; the distinction arising because of a responsible entity's lack of control over Transient Cyber Assets managed by a third-party. NERC explains that the proposed controls for Removable Media do not distinguish between the responsible entity-managed assets and third-party managed assets due to the functionality of Removable Media. NERC provides the example of a thumb drive that can be scanned prior to use regardless of which party manages the asset.[41]

36. NERC explains that proposed Section 5 of Attachment 1 requires responsible entities to meet the security objectives "by implementing the controls that the Responsible Entity determines necessary to meet its affirmative obligation to mitigate the risks of the introduction of malicious code."[42] NERC states that the approach reflected in Section 5 provides the flexibility to implement the controls that best suit the needs and characteristics of a responsible entity's organization. NERC explains further that "the Responsible Entity must demonstrate that its selected controls were designed to meet the security objective to mitigate the risk of the introduction of malicious code."[43]

37. NERC outlines certain distinctions between proposed Section 5 of Attachment 1 to proposed Reliability Standard CIP-003-7 and Attachment 1 to Reliability Standard CIP-010-2. Specifically, NERC states that proposed Section 5 does not include requirements relating to authorization or software vulnerabilities, as are contained in

[41] *Id.* at 28.

[42] *Id.*

[43] *Id.* at 29.

Attachment 1 to Reliability Standard CIP-010-2. NERC explains that this difference is consistent with the risk-based approach of the CIP Reliability Standards and "the underlying principle of concentrating limited industry resources on protecting those BES Cyber Systems with greater risk to the BES." NERC states that Section 5 focuses on the risk associated with the introduction of malicious code.[44]

38. In addition, NERC states that proposed Section 5 to Attachment 1 does not include language requiring a responsible entity to determine whether additional mitigation actions are necessary where a third party manages a Transient Cyber Asset, nor does it include language requiring a responsible entity to implement additional mitigation actions in such situations. NERC states that it nonetheless expects "that if another party's processes and practices for protecting its Transient Cyber Assets do not provide reasonable assurance that they are designed to effectively meet the security objective of mitigating the introduction of malicious code, the Responsible Entity must take additional steps to meet the stated objective."[45] NERC explains that if a third party's practices and policies do not provide reasonable assurance that the Transient Cyber Assets would be protected from malicious code, "simply reviewing those policies and procedures without taking other steps to mitigate the risks of introduction of malicious code may not constitute compliance."[46]

[44] NERC Petition at 29.

[45] *Id.* at 29-30.

[46] *Id.* at 30.

Commission Proposal

39. NERC's proposed modifications in Reliability Standard CIP-003-7, Requirement R2, Attachment 1, Section 5 that include malware detection and prevention controls for responsible entity-managed Transient Cyber Assets and Removable Media should improve the cybersecurity posture of responsibility entities compared to currently-effective Reliability Standard CIP-003-6. The revisions in Section 5.2, however, do not address one aspect of the reliability gap identified in Order No. 822 regarding low impact BES Cyber Systems. Specifically, as noted above, proposed Reliability Standard CIP-003-7 does not explicitly require mitigation of the introduction of malicious code from third-party managed Transient Cyber Assets, even if the responsible entity determines that the third-party's policies and procedures are inadequate.[47] While the proposed Reliability Standard does not explicitly require mitigation of the introduction of malicious code from third-party managed Transient Cyber Assets, NERC states that the failure to mitigate this risk "may not constitute compliance."[48] NERC's statement suggests that, with regard to low impact BES Cyber Systems, the proposed requirement lacks an obligation for a responsible entity to correct any deficiencies that are discovered during a review of third-party Transient Cyber Asset management practices. Indeed, the parallel provision for high and medium impact BES Cyber Systems specifies that

[47] *See* NERC Petition at 29-30.

[48] *Id*. at 30.

"Responsible Entities shall determine whether any additional mitigation actions are necessary and implement such actions prior to connecting the Transient Cyber Asset."[49] Yet, such language obligating mitigation action is not proposed for low impact BES Cyber Assets.

40. The proposed Reliability Standard may, therefore, contain a reliability gap where a responsible entity contracts with a third-party but fails to mitigate potential deficiencies discovered in the third-party's malicious code detection and prevention practices prior to a Transient Cyber Asset being connected to a low impact BES Cyber System. That is because the proposed Reliability Standard does not contain: (1) a requirement for the responsible entity to mitigate any malicious code found during the third-party review(s); or (2) a requirement that the responsible entity take reasonable steps to mitigate the risks of third party malicious code on their systems, if an arrangement cannot be made for the third-party to do so. Without these obligations, we are concerned that responsible entities could, without compliance consequences, simply accept the risk of deficient third-party transient electronic device management practices.[50] Moreover, the requirement to

[49] Reliability Standard CIP-010-2 (Cyber Security – Configuration Change Management and Vulnerability Assessments), Requirement R4, Attachment 1, Section 2.3. In contrast, the obligations to "review" methods used by third-parties to detect and prevent malware are similar for lower, medium and high impact BES Cyber Assets. *Cf.* CIP-010-2, Attachment 1, Sections 2.1 and 2.2; and proposed CIP-010-3, Attachment 1, Section 3.2.

[50] *See* Order No. 706, 122 FERC ¶ 61,040 at P 150 (rejecting the concept of acceptance of risk in the CIP Reliability Standards).

"review" methods used by third-parties to detect and prevent malware may fail to convey the necessary next steps that a responsible entity should take.[51]

41. Therefore, pursuant to section 215(d)(5) of the FPA, we propose to direct that NERC develop modifications to proposed Reliability Standard CIP-003-7 to address the need to mitigate the risk of malicious code that could result from third-party Transient Cyber Assets consistent with the above discussion. The Commission seeks comment on this proposal.

C. Proposed NERC Glossary Definitions

42. Proposed Reliability Standard CIP-003-7 includes two revised definitions for inclusion in the NERC Glossary. Specifically, NERC proposes to revise the definitions of Transient Cyber Asset and Removable Media in order to accommodate the use of the terms at all impact levels. NERC explains that the original definitions include references to concepts or requirements associated only with high and medium impact BES Cyber Systems and the definitions were modified to avoid confusion because protections for Transient Electronic Devices will now be extended to low impact BES Cyber Systems.[52]

43. In addition, NERC proposes to retire the definitions of LERC and LEAP. NERC states that the proposed retirement of the NERC Glossary terms LERC and LEAP accords with the proposed modifications to Section 3 of Attachment 1 to proposed Reliability Standard CIP-003-7 and is intended to simplify the electronic access control

[51] *See* Order No. 791, 145 FERC ¶ 61,160 at P 108.

[52] NERC Petition at 30.

requirements for low impact BES Cyber Systems by avoiding the ambiguities associated with the term "direct." NERC explains further that it "recognized that distinguishing between 'direct' and 'indirect' electronic access within the LERC definition added a layer of unnecessary complexity."[53]

44. We propose to approve the revised definitions of Transient Cyber Asset and Removable Media, as well as the retirement of the definitions of LERC and LEAP.

D. Implementation Plan and Effective Dates

45. NERC requests an effective date for proposed Reliability Standard CIP-003-7 and the revised definitions of Transient Cyber Asset and Removable Media on the first day of the first calendar quarter that is eighteen months after the effective date of the Commission's order approving the proposed Reliability Standard. NERC explains that the proposed implementation plan does not alter the previously-approved compliance dates for Reliability Standard CIP-003-6 other than the compliance date for Reliability Standard CIP-003-6, Requirement R2, Attachment 1, Sections 2 and 3, which would be replaced with the effective date for proposed Reliability Standard CIP-003-7. NERC also proposes that the retirement of Reliability Standard CIP-003-6 and the associated definitions become effective on the effective date of proposed Reliability Standard CIP-003-7.[54]

[53] *Id.* at 16.

[54] *Id.*, Exhibit C (Implementation Plan).

46. We propose to approve NERC's implementation plan for proposed Reliability Standard CIP-003-7, as described above.

E. Violation Risk Factor/Violation Severity Level Assignments

47. NERC requests approval of two violation risk factors and violation severity levels assigned to proposed Reliability Standard CIP-003-7. Specifically, NERC requests approval of violation risk factor and violation severity level assignments associated with Requirements R1 and R2 of Reliability Standard CIP-003-7.[55] We propose to accept these violation risk factors and violation severity levels.

III. Information Collection Statement

48. The FERC-725B information collection requirements contained in this Proposed Rule are subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[56] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[57] Upon approval of a collection of information, OMB will assign an OMB control number and expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number. The Commission solicits comments on the Commission's need for this information, whether the

[55] *Id.*, Exhibit F (Analysis of Violation Risk Factors and Violation Severity Levels).

[56] 44 U.S.C. 3507(d) (2012).

[57] 5 CFR 1320.11 (2017).

information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

49. The Commission bases its paperwork burden estimates on the changes in paperwork burden presented by the proposed revision to CIP Reliability Standard CIP-003-7 as compared to the current Commission-approved Reliability Standard CIP-003-6. The Commission has already addressed the burden of implementing Reliability Standard CIP-003-6.[58] As discussed above, the immediate rulemaking addresses three areas of modification to the CIP Reliability Standards: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber Systems.

50. The NERC Compliance Registry, as of September 2017, identifies approximately 1,320 U.S. entities that are subject to mandatory compliance with Reliability Standards. Of this total, we estimate that 1,100 entities will face an increased paperwork burden under proposed Reliability Standard CIP 003-7, estimating that a majority of these

[58] *See* Order No. 822, 154 FERC ¶ 61,037 at PP 84-88.

entities will have one or more low impact BES Cyber Systems. Based on these assumptions, we estimate the following reporting burden:

RM17-11-000 NOPR (Mandatory Reliability Standards for Critical Infrastructure Protection Reliability Standards)						
	Number of Respondents (1)	**Annual Number of Responses per Respondent (2)**	**Total Number of Responses (1)*(2)=(3)**	**Average Burden & Cost Per Response[59] (4)**	**Total Annual Burden Hours & Total Annual Cost (3)*(4)=(5)**	**Cost per Respondent ($) (5)÷(1)**
Create low impact TCA assets plan (one-time)[60]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
Updates and reviews of low impact TCA assets (ongoing)[61]	1,100	300[62]	330,000	1.5 hrs.[63]; $126	495,000 hrs.; $41,580,000	$37,800

[59] The loaded hourly wage figure (includes benefits) is based on the average of three occupational categories for 2016 found on the Bureau of Labor Statistics website (http://www.bls.gov/oes/current/naics2_22.htm):

Legal (Occupation Code: 23-0000): $143.68

Electrical Engineer (Occupation Code: 17-2071): $68.12

Office and Administrative Support (Occupation Code: 43-0000): $40.89

($143.68 + $68.12 + $40.89) ÷ 3 = $84.23. The figure is rounded to $84.00 for use in calculating wage figures in this NOPR.

[60] This one-time burden applies in Year One only.

[61] This ongoing burden applies in Year 2 and beyond.

[62] We estimate that each entity will perform 25 updates per month. 25 updates *12 months = 300 updates (i.e. responses) per year.

[63] The 1.5 hours of burden per response is comprised of three sub-categories:

Updates to managed low TCA assets: 15 minutes (0.25 hours) per response

Updates to unmanaged low TCA assets: 60 minutes (1 hour) per response

Reviews of low TCA applicable controls: 15 minutes (0.25 hours) per response.

Update/modify documentation to remove LERC and LEAP (one-time)[60]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
Update paperwork for access control implementation in Section 2[64] and Section 3[65] (ongoing)[61]	1,100	1	1,100	20 hrs.; $1,680	6,875 hrs.; $1,848,000	$1,680
TOTAL (one-time)[60]			**2,200**		**13,750 hrs.; $3,696,000**	
TOTAL (ongoing)[61]			**331,100**		**501,875 hrs.; $43,428,000**	

51. The following shows the annual cost burden for each group, based on the burden hours in the table above:

- Year 1: $3,696,000
- Years 2 and 3: $43,428,000
- The paperwork burden estimate includes costs associated with the initial development of a policy to address requirements relating to: (1) clarifying the obligations pertaining to electronic access control for low impact BES Cyber Systems; (2) adopting mandatory security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems) used at low impact BES Cyber Systems; and (3) requiring responsible entities to have a policy for declaring and responding to CIP Exceptional Circumstances related to low impact BES Cyber

[64] Physical Security Controls.

[65] Electronic Access Controls.

Systems. Further, the estimate reflects the assumption that costs incurred in year 1 will pertain to policy development, while costs in years 2 and 3 will reflect the burden associated with maintaining logs and other records to demonstrate ongoing compliance.

52. Title: Mandatory Reliability Standards, Revised Critical Infrastructure Protection Reliability Standards

Action: Proposed Collection FERC-725B.

OMB Control No.: 1902-0248.

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

Frequency of Responses: On Occasion.

Necessity of the Information: This proposed rule proposes to approve the requested modifications to Reliability Standards pertaining to critical infrastructure protection. As discussed above, the Commission proposes to approve NERC's proposed revised CIP Reliability Standard CIP-003-7 pursuant to section 215(d)(2) of the FPA because it improves upon the currently-effective suite of cyber security CIP Reliability Standards.

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

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

54. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the Commission, and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285]. For security reasons, comments to OMB should be submitted by e-mail to: oira_submission@omb.eop.gov. Comments submitted to OMB should include Docket Number RM17-11-000 and OMB Control Number 1902-0248.

IV. Regulatory Flexibility Act Analysis

55. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of Proposed Rules that will have significant economic impact on a substantial number of small entities.[66] The Small Business Administration's (SBA) Office of Size Standards develops the numerical definition of a small business.[67] The SBA revised its size standard for electric utilities (effective January 22, 2014) to a standard based on the number of employees, including affiliates (from the prior standard based on megawatt hour sales).[68] Proposed Reliability Standard CIP-003-7 is expected to impose an

[66] 5 U.S.C. 601-12 (2012).

[67] 13 CFR § 121.101 (2017).

[68] SBA Final Rule on "Small Business Size Standards: Utilities," 78 FR 77343 (Dec. 23, 2013).

additional burden on 1,100 entities[69] (reliability coordinators, generator operators, generator owners, interchange coordinators or authorities, transmission operators, balancing authorities, transmission owners, and certain distribution providers).

56. Of the 1,100 affected entities discussed above, we estimate that approximately 857 or 78 percent[70] of the affected entities are small. As discussed above, proposed Reliability Standard CIP-003-7 enhances reliability by providing criteria against which NERC and the Commission can evaluate the sufficiency of an entity's electronic access controls for low impact BES Cyber systems, as well as improved security controls for transient electronic devices (e.g., thumb drives, laptop computers, and other portable devices frequently connected to and disconnected from systems). We estimate that each of the 857 small entities to whom the proposed modifications to Reliability Standard CIP-003-7 applies will incur one-time costs of approximately $3,360 per entity to implement this standard, as well as the ongoing paperwork burden reflected in the Information Collection Statement (approximately $39,480per year per entity). We do not consider the estimated costs for these 857 small entities to be a significant economic impact.

[69] Public utilities may fall under one of several different categories, each with a size threshold based on the company's number of employees, including affiliates, the parent company, and subsidiaries. For the analysis in this NOPR, we are using a 500 employee threshold due to each affected entity falling within the role of Electric Bulk Power Transmission and Control (NAISC Code: 221121).

[70] 77.95 percent.

57. Based on the above analysis, we propose to certify that the proposed Reliability Standard will not have a significant economic impact on a substantial number of small entities.

V. Environmental Analysis

58. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[71] The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. Included in the exclusion are rules that are clarifying, corrective, or procedural or that do not substantially change the effect of the regulations being amended.[72] The actions proposed herein fall within this categorical exclusion in the Commission's regulations.

VI. Comment Procedures

59. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER**]. Comments must refer to Docket No. RM17-11-000, and must include the commenter's name, the organization they represent, if applicable, and address.

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

[72] 18 CFR 380.4(a)(2)(ii) (2017).

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

61. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street, NE, Washington, DC 20426.

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

VII. Document Availability

63. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

64. From the Commission's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and

Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number of this document, excluding the last three digits, in the docket number field.

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

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

161 FERC ¶ 61,048
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, and Robert F. Powelson.

Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events — Docket No. RM15-11-002

ORDER ON GMD RESEARCH WORK PLAN

(Issued October 19, 2017)

1. On May 30, 2017, the North American Electric Reliability Corporation (NERC) filed a geomagnetic disturbance (GMD) research work plan (GMD Work Plan) for Commission review, as directed in Order No. 830.[1] As discussed below, we accept the GMD Work Plan. In addition, we direct NERC to file for Commission review a final, or otherwise updated, GMD Work Plan within six months of the date of this order.

I. Background

A. GMD Orders and Reliability Standard TPL-007-1

2. In Order No. 779, the Commission directed NERC to develop and submit Reliability Standards addressing GMD events in two stages.[2] For the First Stage GMD Reliability Standards, NERC was directed to submit a Reliability Standard that requires owners and operators of the Bulk-Power System to develop operational procedures to

[1] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, Order No. 830, 81 Fed. Reg. 67,120 (Sept. 30, 2016), 156 FERC ¶ 61,215 (2016), *reh'g denied*, Order No. 830-A, 158 FERC ¶ 61,041 (2017).

[2] *Reliability Standards for Geomagnetic Disturbances*, Order No. 779, 78 Fed. Reg. 30,747 (May 23, 2013), 143 FERC ¶ 61,147, *reh'g denied*, 144 FERC ¶ 61,113 (2013).

mitigate the effects of GMD events.[3] Order No. 779 stated that the Second Stage GMD Reliability Standards must identify one or more "benchmark GMD events" that specify what severity GMD events a responsible entity must assess for potential impacts on the Bulk-Power System. Order No. 779 also directed that, if the assessments identify potential impacts from benchmark GMD events, the Reliability Standards should require owners and operators to develop and implement a plan to protect against instability, uncontrolled separation, or cascading failures of the Bulk-Power System, caused by damage to critical or vulnerable Bulk-Power System equipment, or otherwise, as a result of a benchmark GMD event. Order No. 779 further stated that the development of this plan cannot be limited to considering operational procedures or enhanced training alone, but will, subject to the potential impacts of the benchmark GMD events identified in the assessments, contain strategies for protecting against the potential impact of GMDs based on factors such as the age, condition, technical specifications, system configuration, or location of specific equipment. Order No. 779 noted that these strategies could, for example, include automatically blocking geomagnetically-induced currents (GICs) from entering the Bulk-Power System, instituting specification requirements for new equipment, inventory management, isolating certain equipment that is not cost effective to retrofit, or a combination thereof. Order No. 779 directed NERC to submit the Second Stage GMD Reliability Standards for Commission approval within 18 months of the effective date of Order No. 779 (i.e., by January 22, 2015).

3. On January 21, 2015, NERC submitted for Commission approval Reliability Standard TPL-007-1 (Transmission System Planned Performance for Geomagnetic Disturbance Events) in response to Order No. 779. On September 22, 2016, the Commission issued Order No. 830 approving Reliability Standard TPL-007-1 but also directing NERC to develop three modifications to the Second Stage GMD Reliability Standard: (1) modify the "benchmark GMD event" definition set forth in Attachment 1 of the Reliability Standard so that the "reference peak geoelectric field amplitude" component of the definition is not based solely on spatially-averaged data; (2) develop revisions to the Reliability Standard to require applicable entities to collect and make available necessary data from GIC monitors and magnetometers to ensure a more complete set of data for planning and operational needs; and (3) develop revisions to the Reliability Standard to establish specific deadlines for the development of corrective action plans and the completion of activities called for in corrective action plans. Order No. 830 required NERC to comply with these directives by May 2018.

[3] NERC submitted the First Stage GMD Reliability Standard, EOP-010-1, which the Commission approved in Order No. 797. *Reliability Standard for Geomagnetic Disturbance Operations*, Order No. 797, 79 Fed. Reg. 35,911 (June 25, 2014), 147 FERC ¶ 61,209*, reh'g denied*, Order No. 797-A, 149 FERC ¶ 61,027 (2014).

4. To adequately address the threats posed by GMDs, Order No. 830 further directed NERC to submit within six months of the effective date of Order No. 830 (i.e., by May 30, 2017) a GMD research work plan. The Commission identified research areas for NERC to include in the GMD research work plan, including for example: (1) analyze the area over which spatial averaging should be calculated for stability studies, including performing sensitivity analyses on squares less than 500 km per side (e.g., 100 km, 200 km); (2) analyze earth conductivity models by, for example, using metered GIC and magnetometer readings to calculate earth conductivity and using 3-D earth conductivity readings; (3) determine whether new analyses and observations support modifying the use of single station readings around the earth to adjust the spatially averaged benchmark for latitude; (4) research aspects of the required thermal impact assessments; and (5) in NERC's discretion, conduct any GMD-related research areas generally that may impact the development of new or modified GMD Reliability Standards.

B. GMD Work Plan

5. On May 30, 2017, NERC filed the GMD Work Plan for Commission review in accordance with Order No. 830. NERC describes the GMD Work Plan as "preliminary" and explains that it developed the GMD Work Plan in collaboration with the Electric Power Research Institute (EPRI) and members of the NERC GMD Task Force.

6. The GMD Work Plan identifies nine GMD-related research areas: (1) further analyze spatial averaging used in the benchmark GMD event definition; (2) further analyze latitude scaling; (3) improve earth conductivity models for GIC studies; (4) study GIC field orientation for transformer thermal impact assessments; (5) further analyze 75 amperes per phase criterion used for transformer thermal impact assessments; (6) Section 1600 data request; (7) geoelectric field evaluation and calculation tool; (8) improve harmonics analysis capability; and (9) harmonic impact studies. NERC describes these research areas as being "capable of producing work product that would advance understanding of GMD events and the risks these high-impact, low frequency-events pose to the reliability of the [Bulk-Power System]."[4] NERC states that each research area has an expected deliverable (e.g., technical report or a publicly-available model or tool). The GMD Work Plan summarizes the nine research activities and provides an estimated time frame for completion. In its filing, NERC requests Commission guidance on how to prioritize these research areas, which "would aid in the

[4] NERC Filing at 2.

development of a timetable for submitting informational filings to the Commission reporting on the results of research."[5]

7. NERC states that the GMD Work Plan will require "an extensive, multi-year effort requiring scientific and technical expertise from a variety of disciplines."[6] NERC cautions that it does not have the necessary expertise to complete the research in the GMD Work Plan in-house and outsourcing that work will cost an estimated $2.72 million.[7] NERC maintains that organizations such as EPRI are capable of managing such a project. NERC explains that it will "work over the next several months to identify an appropriate project administration structure to drive completion of the activities in the [GMD Work Plan] in a cost-effective and efficient manner."[8] NERC also states that it will conduct outreach with governmental agencies in the U.S., Europe, and Canada as well as with academia, vendors, and industry to find ways to "identify opportunities to leverage existing GMD-related work and research synergies, develop an appropriate research management structure, and identify alternative funding."[9] NERC concludes by indicating that it will develop additional project details within the next six months and "commits to keep Commission staff informed of the status of these efforts."[10]

8. As contemplated in Order No. 830, the Commission noticed the GMD Work Plan for public comment.[11] The Commission received comments from Edison Electric Institute (EEI) and David Bardin, the latter of whom submitted three sets of comments.[12]

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[5] *Id.* at 3.

[6] *Id.* at 2.

[7] NERC Filing, Attachment 1 at 21 (stating that including information technology investments, the estimated cost increases to $3-3.5 million).

[8] NERC Filing at 2.

[9] *Id.* at 3.

[10] *Id.*

[11] Order No. 830, 156 FERC ¶ 61,215 at P 26 n.33.

[12] In a fourth filing Bardin requested that the Commission take notice of a document issued by the U.S. Geological Survey (USGS) stating that the President's fiscal year 2018 budget request would defund the USGS Geomagnetism Program.

II. Discussion

9. As discussed below, the Commission accepts the GMD Work Plan submitted by NERC. In addition, the Commission: (1) directs NERC to file for Commission review a final, or otherwise updated, GMD Work Plan within six months of the date of this order and in the interim continue to communicate with Commission staff on NERC's progress; (2) reiterates the directive in Order No. 830 that the GMD Work Plan should evaluate the present reliance on single station readings for the purpose of geomagnetic scaling; (3) as requested by NERC, provides guidance on what research tasks should receive priority in the GMD Work Plan; and (4) addresses other issues, including those raised in the comments.

A. Submission of Final GMD Work Plan

10. The GMD Work Plan constitutes a substantial research effort by NERC. Although it lacks significant details, the preliminary GMD Work Plan provided the Commission with useful information on NERC's progress. In addition, submission of the preliminary GMD Work Plan afforded the public an opportunity to review and comment on NERC's plan while also allowing NERC an opportunity to ask for the Commission's guidance on NERC's plan.

11. In acknowledging that the submitted GMD Work Plan is preliminary, NERC committed to completing detailed planning work within six months of the filing date of the preliminary GMD Work Plan and to keeping Commission staff apprised of the status of its efforts in the interim. The Commission accepts NERC's proposal. The next version of the GMD Work Plan should be specific, particularly with respect to the content and timing of the deliverables for each research task, and address any direction or guidance in this order.

12. Accordingly, the Commission directs NERC to file a final, or otherwise updated, GMD Work Plan within six months of the date of this order. As with the present filing, the next version of the GMD Work Plan submitted by NERC will be noticed for comment and addressed by Commission order.

B. Reliance on Single Station Readings for Latitude Scaling

13. In Order No. 830, the Commission directed that the GMD research work plan should "determine whether new analyses and observations support modifying the use of single station readings around the earth to adjust the spatially averaged benchmark for latitude."[13] Although the second research area in the GMD Work Plan addresses further analysis of latitude scaling, the GMD Work Plan does not appear directly to address

[13] Order No. 830, 156 FERC ¶ 61,215 at P 26.

reevaluating reliance on single station readings when adjusting for latitude. We reiterate that this reevaluation must be included in the final GMD Work Plan.

C. Prioritization of Research Tasks in GMD Work Plan

14. The Commission recognizes that the scope of the GMD research directed in Order No. 830 will likely require NERC to prioritize its efforts. Accordingly, in response to NERC's request for guidance on how to prioritize the research tasks in the GMD Work Plan, the Commission provides the following guidance.

15. The Commission believes that Task 3 (Improve Earth Conductivity Models for GIC Studies) should receive first priority because of the importance of improved earth conductivity models to completing the GMD Vulnerability Assessments required in Reliability Standard TPL-007-1 accurately. Tasks 8 (Improve Harmonics Analysis Capability) and 9 (Harmonics Impact Studies) should receive second priority because the synergistic effects of harmonics during GMD events are not well understood and, as noted by the NERC GMD Task Force, harmonics were a root cause of the 1989 Québec GMD blackout.[14] The Commission believes that third priority should be given to Task 4 (Study GIC Field Orientation for Transformer Thermal Impact Assessments) because such work is necessary to complete Transformer Thermal Impact Assessments effectively because failure to consider orientation of the field may result in inaccurate impact studies. While important areas of research, Tasks 1 (Further Analyze Spatial Averaging Used in the Benchmark GMD Event) and 2 (Further Analyze Latitude Scaling) should receive fourth priority and Tasks 5 (Further Analyze the 75 Ampere Per Phase Criterion Used for Transformer Thermal Impact Assessments) and 7 (Geoelectric Field Evaluation and Calculation Tool) fifth priority.[15]

16. Finally, we do not include Task 6 (Section 1600 Data Request) in our discussion above. This task, unlike the other GMD Work Plan tasks, is not a research project. Rather, its focus is on "develop[ing] the necessary guidance and technical guidelines to support a request for data or information under Section 1600 of the NERC Rules of Procedure…."[16] As explained in Order No. 830, the Commission believes that "additional collection and disclosure of GIC monitoring and magnetometer data is

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[14] NERC, *2012 Special Reliability Assessment Interim Report: Effects of Geomagnetic Disturbances on the Bulk Power System* at 6 (2012), http://www.nerc.com/files/2012GMD.pdf.

[15] Work on Task 5, step 2 (determine the effects of short-term harmonic currents) could be undertaken as part of Tasks 8 and 9.[15]

[16] NERC Filing at 11-12.

necessary to improve our collective understanding of the threats posed by GMD events."[17] This data collection and distribution is critical not only to efforts that might be undertaken in support of the GMD research plan, but efforts elsewhere in government, industry, and academia. This effort is essential to our continued understanding of GMD and its effects on the Bulk-Power System, and NERC should complete this effort as expeditiously as possible.

D. Review of GMD Work Plan Deliverables

17. In its filing, NERC states that it "contemplates that the final deliverable for each Task would be subject to technical and scientific review through the NERC GMD Task Force, engaging outside researchers as necessary."[18] NERC explains that the GMD Task Force "includes participants from U.S. and Canadian government space weather researchers, representatives from the manufacturer and vendor community, and subject matter experts from both within and outside the electric power industry."[19] Because the research tasks set forth in Order No. 830 and the GMD Work Plan implicate various scientific disciplines, the Commission encourages wide participation in the development of the GMD Work Plan deliverables. The Commission also expects NERC to afford interested entities an opportunity to comment on GMD Work Plan deliverables before they are filed with the Commission.

E. Other Issues

18. EEI states that research in the GMD Work Plan should be pursued but "the significant scope and scale of this work and therefore how this research will be funded is a substantive concern."[20] EEI contends that implementing the GMD Work Plan "would extend NERC's authority from developing, modifying, and enforcing the Reliability Standards to implementing research in support of future modifications to the standards … Reliability Standards to this point have been based on existing and known reliability practices and have not required new research to develop such practices, except for [in the case of Reliability Standard FAC-003-2 (Transmission Vegetation Management)]."[21] EEI states that to "avoid setting a precedent," the Commission should "coordinate with

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[17] Order No. 830, 156 FERC ¶ 61,215 at P 88.

[18] NERC Filing at 7.

[19] *Id.* at n.9.

[20] EEI Comment at 2.

[21] *Id.* at 3.

NERC to explore the funding issue with the Department of Energy to determine if a cost share arrangement could be leveraged to fund this research … [and] prioritize the research activities such as Task 1 and 3 to limit the scope and scale of the research."[22]

19. EEI did not seek rehearing of this aspect of Order No. 830. Accordingly, to the extent EEI now requests rehearing of this issue, the request is untimely.[23] Even so, in 2013, the Commission approved NERC's proposed criteria for determining what activities fall within the scope of section 215 of the Federal Power Act. The Commission, *inter alia*, determined that "information gathering, collection and analysis activities to obtain information reasonably necessary in Reliability Standards development, including for purposes of identifying areas in which new Reliability Standards could be developed … [or] existing Reliability Standards could be revised" falls within the scope of section 215.[24] Moreover, as EEI concedes, the GMD work plan is not wholly unprecedented, as the Commission directed NERC to conduct research on Reliability Standard FAC-003-2 regarding minimum clearance distances between vegetation and transmission lines.[25] That research was ultimately performed for NERC under contract by EPRI.[26] Nevertheless, the Commission is amenable to prioritizing NERC's research efforts, as discussed above, and having NERC pursue cost sharing or savings opportunities. However, we note that such efforts should not delay completion of this critical research.

20. In his first set of comments, Bardin states that the GMD Work Plan does not address completion of a three-dimensional magnetotelluric survey of the United States or the development of a "comprehensive magnetometer network."[27] Bardin also maintains that NERC can "compel EPRI and others to make magnetometer data freely accessible by

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[22] *Id.*

[23] 16 U.S.C. § 825l(a) (2012); 18 C.F.R. § 385.713(b) (2017) ("A request for rehearing by a party must be filed not later than 30 days after issuance of any final decision or other final order in a proceeding.").

[24] *North American Electric Reliability Corp.*, 143 FERC ¶ 61,052, at P 33 (2013).

[25] *Revisions to Reliability Standard for Transmission Vegetation Management*, Order No. 777, 142 FERC ¶ 61,208, at P 3 (2013).

[26] *North American Electric Reliability Corp.*, Docket No. RD16-4-000 (2016) (delegated letter order approving Reliability Standard FAC-003-4 (Transmission Vegetation Management)).

[27] June 16, 2017 Bardin Comments.

exercising NERC authority under NERC's own Rules."[28] Bardin also questions NERC's plan to develop further the details of the preliminary GMD Work Plan over the next six months because the delay could "interrupt[] momentum."[29] In his second set of comments, Bardin poses a series of questions, addressed to NERC, meant to clarify the section of the GMD Work Plan (Task 6) devoted to data collection under Section 1600 of the NERC Rules of Procedure. In his third set of comments, Bardin states that the Commission should ask NERC how it will address "challenges … as to collection of data as well as validation of models and testing of hypotheses" and how NERC will learn about new research results and disseminate such information to industry."[30]

21. In response to Bardin's first set of comments, we note that Order No. 830 did not direct NERC to complete three-dimensional magnetotelluric surveys of the United States as part of the GMD research work plan, and therefore find that requiring such a plan is beyond the scope of Order No. 830's requirements. However, we support efforts to complete such a survey, and appreciate the work being done by the United States Geological Survey's geomagnetism program, which provides important data and research that support broader GMD efforts. With respect to developing a "comprehensive magnetometer network," NERC will address this issue as part of the directed revisions to Reliability Standard TPL-007-1. Specifically, Order No. 830 directed NERC to modify Reliability Standard TPL-007-1 to require the collection of necessary GIC monitoring and magnetometer data and to make such data publicly available, which could be achieved by leveraging existing magnetometers or, if necessary, installing new magnetometers.

22. As for Bardin's comment regarding compelling magnetometer data from EPRI, Order No. 830-A stated that NERC cannot compel EPRI to provide data to NERC because EPRI is not subject to the Commission's jurisdiction.[31] Instead, Order No. 830 directed NERC to gather data from users, owners, and operators of the Bulk-Power System through a Section 1600 data request under the NERC Rules of Procedure and through the reporting requirements in the future version of Reliability Standard TPL-007-1. We reiterate the importance of that data collection effort and note that, while we cannot compel EPRI to provide data to NERC, we encourage EPRI to do so on a voluntary basis to further support GMD research efforts. We also disagree with the contention that additional time to finalize the GMD Work Plan might adversely

[28] *Id.* at 3.

[29] *Id.*

[30] June 23, 2017 Bardin Comments at 1.

[31] Order No. 830-A, 158 FERC ¶ 61,041 at P 26 n.25.

impact NERC's research activities. As discussed above, NERC's efforts in preparing and submitting the preliminary GMD Work Plan, while incomplete, provided the Commission with useful information. In Order No. 830, the Commission recognized that NERC might require additional time to complete the GMD Work Plan.[32] We find in this instance that additional time to finalize details of the GMD Work Plan is reasonable.

23. Bardin's second and third sets of comments generally seek clarification from NERC regarding elements of the GMD Work Plan. We encourage NERC to consider these questions in the first instance when preparing the final, or otherwise updated, GMD Work Plan.

The Commission orders:

(A) The Commission accepts the preliminary GMD Work Plan, as discussed in the body of this order.

(B) The Commission directs NERC to submit a final, or otherwise updated, GMD Work Plan within six months of the date of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[32] Order No. 830, 156 FERC ¶ 61,215 at P 81 ("An extension of time to submit the GMD research work plan may be available if six months proves to be insufficient.").

161 FERC ¶ 61,159
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 40

[Docket No. RM16-22-000]

Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards

(Issued November 16, 2017)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) proposes to approve Reliability Standards PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel) submitted by the North American Electric Reliability Corporation (NERC). The purpose of proposed Reliability Standard PRC-027-1 is to maintain the coordination of protection systems installed to detect and isolate faults on bulk electric system elements, such that those protection systems operate in the intended sequence during faults. The purpose of proposed Reliability Standard PER-006-1 is to ensure that personnel are trained on specific topics essential to reliability to perform or support real-time operations of the bulk electric system. In addition, the Commission proposes to direct NERC to develop certain modifications to proposed Reliability Standard PRC-027-1.

DATES: Comments are due **[INSERT DATE 60 days after publication in the**

FEDERAL REGISTER].

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

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

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

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards	Docket No. RM16-22-000

NOTICE OF PROPOSED RULEMAKING

(Issued November 16, 2017)

1. Pursuant to section 215 of the Federal Power Act (FPA), the Commission proposes to approve proposed Reliability Standards PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel), which were submitted for approval by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization (ERO).[1] As discussed below, however, the Commission also proposes to direct NERC to modify proposed Reliability Standard PRC-027-1 to require an initial protection system coordination study to ensure that applicable entities will perform (or have performed), as a baseline, a study demonstrating proper coordination of its protection systems. We propose to direct NERC to submit the modified Reliability Standard for Commission approval within 12 months following the effective date of a final rule in this proceeding.

[1] 16 U.S.C. 824o.

2. The Commission also proposes to approve the associated violation risk factors, violation severity levels, implementation plans, and effective dates proposed by NERC for Reliability Standards PRC-027-1 and PER-006-1. The Commission further proposes to approve the retirement of currently-effective Reliability Standard PRC-001-1.1(ii) (System Protection Coordination).[2]

3. In addition, the Commission proposes to approve new and revised definitions submitted by NERC for incorporation in the NERC Glossary of Terms Used in NERC Reliability Standards ("NERC Glossary") for the following terms: (1) "protection system coordination study;" (2) "operational planning analysis;" and (3) "real-time assessment."

I. Background

A. Section 215 and Mandatory Reliability Standards

4. Section 215 of the FPA requires a Commission-certified ERO to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[3] Once approved, the Reliability Standards may be enforced by the ERO subject to Commission oversight or by the Commission independently.[4] In 2006, the Commission certified NERC as the ERO pursuant to section 215 of the FPA.[5]

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[2] The Commission approved Reliability Standard PRC-001-1.1(ii) on May 29, 2015. *North American Electric Reliability Corporation*, 151 FERC ¶ 61,186 (2015).

[3] *Id.* 824o(c), (d).

[4] *Id.* 824o(e).

[5] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,190,

B. Order No. 693

5. On March 16, 2007, the Commission issued Order No. 693, approving 83 of the 107 Reliability Standards filed by NERC, including Reliability Standard PRC-001-1.[6] In addition, the Commission directed NERC to develop modifications to Reliability Standard PRC-001-1 that:

> (1) correct the references for Requirements, and [*sic*] (2) include a requirement that upon the detection of failures in relays or protection system elements on the Bulk-Power System that threaten reliable operation, relevant transmission operators must be informed promptly, but within a specified period of time that is developed in the Reliability Standards development process, whereas generator operators must also promptly inform their transmission operators; and (3) clarifies that, after being informed of failures in relays or protection system elements that threaten reliability of the Bulk-Power System, transmission operators must carry out corrective control actions, i.e., return a system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes after they receive notice of the failure.[7]

order on reh'g, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[6] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at PP 1433-1449, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[7] Order No. 693, FERC Stats. & Regs. ¶ 31,242 at P 1449.

C. NERC Petition and Proposed Reliability Standards PRC-027-1 and PER-006-1

6. On September 2, 2016, NERC submitted a petition seeking Commission approval of proposed Reliability Standards PRC-027-1 and PER-006-1.[8] NERC states that the proposed Reliability Standards, new and revised NERC Glossary terms, and the retirement of Reliability Standard PRC-001-1.1(ii) satisfy the Commission's criteria in Order No. 672 and are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[9] NERC explains that the intent of the proposed Reliability Standards and changes to the NERC Glossary are to maintain the coordination of protection systems installed to detect and isolate faults on bulk electric system elements and require registered entities to provide training to their relevant personnel on protection systems and remedial action schemes. NERC asserts that the proposed Reliability Standards are an improvement over currently-effective Reliability Standard PRC-001-1.1(ii) and will ensure that appropriate personnel are trained on protection systems and that protection systems are appropriately studied, coordinated, and monitored.

[8] Proposed Reliability Standards PRC-027-1 and PER-006-1 are not attached to this Notice of Proposed Rulemaking. The proposed Reliability Standards are available on the Commission's eLibrary document retrieval system in Docket No. RM16-22-000 and are posted on the NERC website, http://www.nerc.com.

[9] NERC Petition at 10.

1. Proposed Reliability Standard PER-006-1

7. NERC states that proposed Reliability Standard PER-006-1 requires generator operators to use a systematic approach to develop and implement training for dispatch personnel at centrally-located dispatch centers.[10] NERC explains that proposed Reliability Standard PER-006-1 will also cover plant personnel who are responsible for real-time control of a generator. NERC maintains that it is appropriate to train plant personnel [in] the functionality of protection systems and remedial action schemes. NERC observes that proposed Reliability Standard PER-006-1 replaces the phrase "purpose and limitations" used in currently-effective Reliability Standard PRC-001-1(ii) with the phrase "operational functionality" to clearly identify the objective of the training.[11] NERC also observes that proposed Reliability Standard PER-006-1 replaces the phrase "applied in its area" in Reliability Standard PRC-001-1.1(ii) with the phrase "that affect the output of the generating facility(ies) it operates" to properly tailor the scope of the required training. NERC notes that proposed Reliability Standard PER-006-1 does not specify a periodicity for the required training.

2. Proposed Reliability Standard PRC-027-1

8. NERC asserts that proposed Reliability Standard PRC-027-1:

> provides a clear set of Requirements that obligate entities to (1) implement a process for establishing and coordinating new or revised Protection System settings, and

[10] *Id.* at 13.

[11] *Id.* at 15.

> (2) periodically study Protection System settings that could be affected by incremental changes in Fault current to ensure the Protection Systems continue to operate in their intended sequence.[12]

According to NERC, proposed Reliability Standard PRC-027-1, Requirement R1 mandates that each transmission owner, generator owner, and distribution provider establish a process for developing new and revised protection system settings for bulk electric system elements.[13]

9. NERC states that proposed Reliability Standard PRC-027-1, Requirement R2 mandates that every six years, applicable entities must either: (1) perform a protection system coordination study to determine whether the protection systems continue to operate in the intended sequence during faults; (2) compare present fault current values to an established fault current baseline and, only if the comparison identifies a 15 percent or greater deviation in fault current values (either three phase or phase to ground) at a bus to which the bulk electric system is connected, perform a protection system coordination study; or (3) use a combination of options 1 and 2.[14]

10. NERC explains that proposed Reliability Standard PRC-027-1, Requirement R3 will require applicable entities to use the process established under proposed Reliability

[12] *Id.* at 26.

[13] *Id.* at 27.

[14] *Id.* at 26.

Standard PRC-027-1, Requirement R1 for the development of any new or revised protection system settings.

3. Proposed Retirement of Reliability Standard PRC-001-1.1(ii)

11. NERC states that Reliability Standard PRC-001-1.1(ii) includes six requirements that are either addressed by Reliability Standards approved by the Commission or by the proposed Reliability Standards. Specifically, NERC explains that Reliability Standard PRC-001-1.1(ii), Requirement R1 has been partially replaced by currently-effective Reliability Standards PER-003-1 and PER-005-2. NERC continues that proposed Reliability Standard PER-006-1 and the proposed revised definitions of operational planning analysis and real-time assessment will replace the remaining portions of Reliability Standard PRC-001-1.1(ii), Requirement R1. NERC asserts that Reliability Standard PRC-001-1.1(ii), Requirement R2 has been addressed by Reliability Standards IRO-001-4, IRO-008-2, IRO-010-2, TOP-001-3, and TOP-003-3, which the Commission approved in Order No. 817.[15] NERC states that Reliability Standard PRC-001-1.1(ii), Requirements R3 and R4 will be replaced with proposed Reliability Standard PRC-027-1. NERC also explains that Reliability Standard PRC-001-1.1(ii), Requirement R5 has been replaced with several Reliability Standards developed after Reliability Standard PRC-001-1(ii) became effective.[16] NERC further states that Reliability

[15] *Id*. at 5 (citing *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015)).

[16] *Id.* at 6.

Standard PRC-001-1.1(ii), Requirement R6 has been replaced with Reliability Standards TOP-001-3 and TOP-003-3.

II. Discussion

12. Pursuant to section 215(d)(2) of the FPA, we propose to approve proposed Reliability Standards PER-006-1 and PRC-027-1 as just, reasonable, not unduly discriminatory or preferential, and in the public interest, as both proposed Reliability Standards improve upon currently-effective Reliability Standard PRC-001-1.1(ii) in important ways.[17] Specifically, proposed Reliability Standard PRC-027-1 does so by (1) modifying the applicability section to include the appropriate functional entity types with the responsibilities, resources, and skill sets to conduct the studies required to coordinate protection systems, and (2) listing the protection system functions on all bulk electric system elements that require coordination. Proposed Reliability Standard PER-006-1, along with existing formal training requirements in the PER group of Reliability Standards, also improves upon Reliability Standard PRC-001-1.1(ii), Requirement R1 by ensuring that the necessary personnel are familiar with and understand the purpose and limitations of protection systems schemes while providing more precise and auditable requirements. However, proposed Reliability Standard PRC-027-1, Requirement R2, Option 2 does not appear to ensure coordination of all bulk electric system elements with protection system functions. Accordingly, pursuant to section 215(d)(5) of the FPA, we

[17] 16 U.S.C. 824o(d)(2).

propose to direct that NERC develop modifications to proposed Reliability Standard PRC-027-1 that address our concern regarding this gap, as discussed below.

13. In addition, we propose to approve NERC's associated violation risk factors, violation severity levels, implementation plans, and effective dates. We also propose to approve the revised definitions for inclusion in the NERC Glossary. Further, we propose to approve the retirement of Reliability Standard PRC-001-1.1(ii), as requested by NERC.

14. Pursuant to 215(d)(5) of the FPA, we propose to direct that NERC develop modifications to proposed Reliability Standard PRC-027-1 addressing our concern that applicable entities that choose Requirement R2, Option 2 perform (or have already performed) an initial baseline study demonstrating proper coordination of their protection systems. Any additional protection system coordination studies would be necessary only if an applicable entity is confronted with 15 percent or greater fault current deviations from the prior baseline study amounts, as currently proposed in Reliability Standard PRC-027-1, Requirement R2, Option 2. We propose to direct NERC to submit the modified Reliability Standard within 12 months following the effective date of a final rule in this proceeding.

15. Proposed Reliability Standard PRC-027-1, Requirement R2 does not require an initial protection system coordination study if an applicable entity elects Option 2. Unlike Option 1, which requires performance of protection system coordination studies every six years, Option 2 requires applicable entities to "[c]ompare present Fault current values to an established Fault current baseline and perform a Protection System

Coordination Study when the comparison identifies a 15 percent or greater deviation." The proposed Reliability Standard and NERC's petition do not indicate that the "Fault current baseline" must be established through an initial protection system coordination study. Instead, NERC's petition states that the baseline must be established "by the effective date of the standard based on short-circuit studies."[18] The proposed Reliability Standard provides that "the initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed," but this language does not require establishing the "initial Fault current baseline" through an initial protection system coordination study.[19] NERC's petition reinforces this understanding, as noted above, by explicitly allowing the use of short-circuit studies to establish the initial Fault current baseline.

16. While they are related terms, we understand there to be a difference between short-circuit studies and protection system coordination studies. NERC defines protection system coordination study as an "analysis to determine whether Protection Systems operate in the intended sequence during Faults."[20] By comparison, proposed

[18] NERC Petition at 36 n.35.

[19] Proposed Reliability Standard PRC-027-1, Requirement R2, Option 2 n.1. Footnote 1 further states that if an "initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new BES Element, the entity *may* establish the baseline by performing a Protection System Coordination Study" (emphasis added). *Id.*

[20] NERC Petition, Exhibit A-3, Proposed Definitions. This definition is consistent with the definition of coordination of protection in IEEE Std. C37.113-1999 (stating that the "process of choosing settings or time delay characteristics of protective devices, such

Reliability Standard PRC-027-1 explains that a short-circuit study is "an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical fault … [and] are used as the basis for protection device coordination studies."[21] Therefore, while short-circuit studies are inputs to protection system coordination studies, it appears that a short-circuit study differs in scope from a protection system coordination study. Based on this record, it would be incorrect to conclude that proposed Reliability Standard PRC-027-1, Requirement R2, Options 1 and 2 afford the same level of protection system coordination because the former requires a protection system coordination study while the latter does not.

17. While we generally support permitting flexibility in the Reliability Standards to achieve required performance goals, the possibility that some bulk electric system elements may never undergo a protection system coordination study raises reliability concerns. In past serious Bulk-Power System events, mis-coordination was a contributing factor to misoperations and outages. For example, the Arizona Southern California September 8, 2011 Outage Report identified an instance where a transmission owner did not perform a protection system coordination study prior to the implementation

that operation of the devices will occur in a specified order to minimize customer service interruption and power system isolation due to a power system disturbance").

[21] Proposed Reliability Standard PRC-027-1, Supplemental Material at 8.

of a protection system.[22] The 2011 Outage Report stated that this omission negatively affected the reliable operation of the Bulk-Power System during the 2011 event.[23]

18. Over the past eleven years, several NERC reports have addressed the importance of protection system coordination to Bulk-Power System reliability. Proposed Reliability Standard PRC-027-1 addresses some of the issues raised in these reports; but without requiring an initial protection system coordination study, the proposed Reliability Standard does not address all of them. In 2006, for example, the NERC System Protection Control Task Force assessed Reliability Standard PRC-001.[24] The report recommended requiring the coordination of all existing protection systems.[25]

19. In 2009, in a letter from the NERC President to the NERC Board of Trustees and stakeholders, NERC identified generation and transmission mis-coordination as responsible for 30 percent of the misoperations that occurred between 2005 and 2008.[26] The 2009 letter stated that mis-coordination between generation and transmission

[22] Arizona Southern California September 8, 2011 Outage Report at 101-103, https://www.ferc.gov/legal/staff-reports/04-27-2012-ferc-nerc-report.pdf.

[23] *Id.* at 100-102.

[24] NERC SPCTF Assessment of Standard PRC-001-0 – System Protection Coordination (2006), http://www.nerc.com/pa/Stand/Project 200706 System Protection Coordination DL/NERC_SPCTF_Assessment_of_Standard_PRC.pdf.

[25] *Id.* at 3-4.

[26] NERC Letter from Rick Sergel, NERC President, Regarding System Protection Initiative at Figure 2 (April 24, 2009).

protection systems "has caused two significant system disturbances in the past two years, and resulted in the unnecessary loss of generation during seven additional disturbances in that timeframe."[27] The letter explained that the 2009 NERC System Protection Initiative would initially focus on the area of protection system coordination.[28]

20. In 2013, NERC issued a Misoperations Report prepared by the Protection System Misoperations Task Force.[29] The Misoperations Report identified "ways to potentially reduce the amount of future misoperations" and concluded that "[m]isoperations due to setting errors can potentially be reduced."[30] The identified techniques to reduce incorrect settings, included: peer reviews, increased training, more extensive fault studies, standard templates for setting standard schemes using complex relays, and periodic review of existing settings when there is a change in system topography.[31] In the

[27] *Id.* at 1.

[28] *Id.* at 1-2.

[29] NERC Misoperations Report (2013), http://www.nerc.com/comm/PC/Protection%20System%20Misoperations%20Task%20Force%20PSMTF%202/PSMTF_Report.pdf.

[30] *Id.* at 3.

[31] *Id.*

ReliabilityFirst region, NERC identified a category of misoperations caused by "Engineering/Design Issues," which specifically included setting mis-coordination.[32] This category of misoperations was one of the three most common causes of misoperations for above 200 kV facilities within the ReliabilityFirst region.[33] The positive impact on Bulk-Power System reliability of reducing misoperations because of "Incorrect setting/logic/design errors" is found in NERC's 2015 Analysis of System Protection Misoperations:

> The State of Reliability 2015 report found that protection system misoperations continued to be a significant contributor to automatic transmission outage severity. In general, transmission system events with protection system misoperations were more impactful than other transmission events. They were also a significant contributor to transmission outage severity, indicating that a reduction in protection system misoperations would lead to an improvement in system reliability.[34]

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[32] *Id.* at 14-15. The 2013 Misoperations Report elaborated that the "Engineering/Design Issues" category included:

> Incorrect short circuit values and coordination errors. The incorrect short circuit values included outdated or incorrect data used to calculate relay settings. The coordination errors in these cases all involved pilot protection either of insufficient carrier blocking trip delays or of improper choice of ground pickup values used in a blocking scheme. *Id.* at 15.

[33] *Id*. at 14.

[34] NERC, Analysis of System Protection Misoperations at 1 (Dec. 2015) (citations omitted), http://www.nerc.com/pa/RAPA/PA/Performance%20Analysis%20DL/2015_Analysis_of_System_Protection_Misoperations_Final.pdf (finding that 31 percent of all misoperations were due to "Incorrect setting/logic/design errors").

21. In 2014, a NERC "lessons learned" document on "Generation Relaying – Underfrequency Protection Coordination" identified a 2014 incident where underfrequency relay trip settings were installed on the system unnecessarily and were not coordinated with a generator's relay trip setting.[35] The document explained that "[u]nintended generator tripping during an underfrequency event can exacerbate the condition."[36] The document also stated that "generator relay protection should be coordinated with all auxiliary power system relaying with specific regard to time-delay settings" in order to ensure reliable generator operation.[37]

22. The 2016 State of Reliability Report noted that while protection system misoperations declined in 2015, misoperations showed a "statistically significant positive correlation with transmission outage severity and show[ed] a higher relative transmission risk."[38] Misoperations showed the strongest correlation of the factors considered. In addition, the 2016 State of Reliability Report identified that "over 40 percent of the

[35] NERC, Lesson Learned, Generation Relaying – Underfrequency Protection Coordination (2014), http://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20140601_Generation_Relaying_Underfrequency_Protection_Coordination_final.pdf.

[36] *Id.*

[37] *Id.*

[38] 2016 State of Reliability Report at 17, http://www.nerc.com/pa/RAPA/Pages/default.aspx.

incorrect setting/logic/design misoperations were due to the miss coordination [*sic*] of ground overcurrent settings" found by ERCOT.[39]

23. The 2017 State of Reliability Report recognized the significance of protection system misoperations to Bulk-Power System reliability by observing that "[p]rotection system misoperations should remain an area of focus as it continues to be one of the largest contributors to the severity of transmission outages."[40]

24. For the reasons discussed above, we propose to direct that NERC develop modifications to proposed Reliability Standard PRC-027-1 to address our concern by requiring that applicable entities perform an initial protection coordination study under Requirement R2, Option 2. We propose that applicable entities would have six years from the effective date of a modified Reliability Standard to complete the analysis. An applicable entity could use pre-existing protection system coordination studies to satisfy the proposed requirement provided it was reasonable (i.e., no intervening system changes that would render the earlier work obsolete). After conducting the initial protection system coordination study, subsequent protection system coordination studies would only be required when an applicable entity is confronted with 15 percent or greater fault current deviations from the prior baseline study amounts, as currently proposed in Reliability Standard PRC-027-1, Requirement R2, Option 2. We seek comments on this proposal.

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[39] *Id.* at 166.

[40] 2017 State of Reliability Report at 2.

25. Separately, we seek comment from NERC and other interested entities explaining the technical basis for employing a 15 percent deviation threshold in proposed Reliability Standard PRC-027-1, Requirement R2, Option 2. We seek to better understand the basis for this threshold to ensure an adequate record in the proceeding on this matter.

III. Information Collection Statement

26. The collection of information addressed in this Notice of Proposed Rulemaking is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[41] OMB's regulations require approval of certain information collection requirements imposed by agency rules.[42] Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of a rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number.

27. The Commission will submit the information collection requirement to OMB for its final review and approval. We solicit public comments on the need for this information, whether the information will have practical utility, the accuracy of the burden estimates, ways to enhance the quality, utility, and clarity of the information to be

[41] 44 U.S.C. 3507(d).

[42] 5 CFR 1320.11.

collected or retained, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques.

28. The information collection requirements in this Notice of Proposed Rulemaking in Docket No. RM16-22-000 are associated with FERC-725A,[43] FERC-725G6,[44] and FERC-725Y, as discussed below.

29. Public Reporting Burden: The number of respondents below is based on an examination of the NERC compliance registry on April 7, 2017, for transmission owners, generator owners, generator operators, and distribution providers within the United States and an estimate of how many entities from that registry will be affected by the Reliability Standards proposed for adoption and implementation. At the time of Commission review of proposed Reliability Standards PRC-027-1 and PER-006-1, 334 transmission owners, 913 generator owners, 875 generator operators, and 365 distribution providers in the

[43] FERC-725A (OMB Control No. 1902-0244) currently includes the information collection requirements associated with Reliability Standard PRC-001-1.1(ii), which is proposed for retirement. Only one item per OMB Control No. may be pending OMB review at a time, and an unrelated item affecting FERC-725A is pending OMB review. We are providing estimates of the burden reduction related to FERC-725A for review and comment. However, to submit this Notice of Proposed Rulemaking timely to OMB, the Commission is being conservative and not reducing the burden estimates associated with FERC-725A at this time.

[44] The information collection requirements related to proposed Reliability Standard PRC-027-1 would normally be included in FERC-725G (OMB Control No. 1902-0252). However, only one item per OMB Control No. may be pending OMB review at a time, and an unrelated item affecting FERC-725G is pending OMB review. For this Notice of Proposed Rulemaking and the related submittal to OMB, we use a placeholder information collection no. of FERC-725G6.

United States were registered in the NERC compliance registry. However, under NERC's compliance registration program, entities may be registered for multiple functions, so these numbers incorporate some double counting. We note that many generation sites share a common generator owner or generator operator. The following table provides the estimated proposed annual burden and cost related to information collection requirements in this Notice of Proposed Rulemaking.[45]

Proposed Changes in the NOPR in Docket No. RM16-22-000					
Respondent Category and Requirement [46]	**Number of Respondents (1)**	**Annual Number of Responses per Respondent (2)**	**Total Number of Annual Responses (1)*(2)=(3)**	**Average Burden Hours & Cost per Response[47] (4)**	**Annual Burden Hours & Total Annual Cost (rounded)[48] (3)*(4)=(5)**
FERC-725G6 (covering Proposed Reliability Standard PRC-027-1)[49]					

[45] TO=transmission owner; TOP=transmission operator; GO=generator owner; GOP=generator operator; DP=distribution provider; and BA=balancing authority.

[46] For each Reliability Standard, the Measure shows the acceptable evidence for the associated Reporting Requirement, and the Compliance section details the related Recordkeeping Requirement.

[47] Based on data from the Bureau of Labor Statistics, the average hourly cost (wages plus benefits) is $65.69/hour for an engineer, and $39.14/hour for a record clerk. The hourly cost for an engineer is used for reporting requirements; the hourly cost for a record clerk is used for recordkeeping requirements.

[48] For display purposes, the cost figures in column 5 have been rounded.

[49] Some of the reporting requirements are required at least every six calendar years. In this table, the Commission assumes that respondents might work on some of their elements each year; the annual burden estimate shown is one sixth of the burden associated with one complete six-year cycle. For example, for each transmission owner: (a) the annual reporting burden associated with Requirements R1, R2, and R3 is shown as 60 hours per year, and (b) the burden for the six-year cycle would be six times that, or a total of 360 hours.

TO; Reporting Reqs. R1, R2, & R3	334	1	334	60 hrs.; $3,941.40	20,040 hrs.; $1,316,428
TO; Recordkeeping Reqs.	334	1	334	40 hrs.; $1,565.60	13,360 hrs.; $522,910
GO; Reporting Reqs. R1, R2, & R3	913	1	913	10 hrs.; $656.90	9,130 hrs.; $599,750
GO; Recordkeeping Reqs.	913	1	913	10 hrs.; $391.40	9,130 hrs.; $357,348
DP; Reporting Reqs R1, R2, & R3	365	1	365	10 hrs.; $656.90	3,650 hrs.; $239,769
DP; Recordkeeping Reqs.	365	1	365	10 hrs.; $391.40	3,650 hrs.; $142,861
Sub-Total for Reporting Reqs. for FERC-725G6					32,820 hrs.; $2,155,947
Sub-Total for Recordkeeping Reqs. for FERC-725G6					26,140 hrs.; $1,023,119
Total Proposed Increase for FERC-725G6					58,960 hrs.; $3,179,066
FERC-725Y (covering Proposed Reliability Standard PER-006-1)					
GOP; Reporting Req. R1	875	1	875	5 hrs.; $328.45	4,375 hrs.; $287,394
GOP; Recordkeeping Req.	875	1	875	10 hrs.; $391.40	8,750 hrs.; $342,475
Total Proposed Increase for FERC-725Y					13,125 hrs.; $629,869
Reductions to FERC-725A (covering proposed retirement of Reliability Standard PRC-001-1.1)[50]					
GOP; Reporting Req.	875	1	875	40 hrs.; $2,627.60	35,000 hrs.; $2,299,150

[50] The estimates for average annual burden hours per response are based on Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 1906, 1907. The numbers of respondents and estimated hourly costs are based on current figures.

GOP; Recordkeeping Req.	875	1	875	50 hrs.; $1,957.00	43,750 hrs.; $1,712,375
TOP; Reporting Req.	177	1	177	60 hrs.; $3,941.40	10,620 hrs.; $697,628
TOP; Recordkeeping Req.	177	1	177	70 hrs.; $2,739.80	12,390 hrs.; $484,945
BA; Reporting Req.	99	1	99	32 hrs.; $2,102.08	3,168 hrs.; $208,106
BA; Recordkeeping Req.	99	1	99	20 hrs.; $782.80	1,980 hrs.; $77,497
Reduction Sub-Total Reporting Reqs. for FERC-725A					48,788 hrs.; $3,204,884
Reduction Sub-Total Recordkeeping Reqs. for FERC-725A					58,120 hrs.; $2,274,817
Reduction, Sub-Total for FERC-725A					106, 908 hrs.; $5,479,701 (reduction)
NET TOTAL REDUCTION FOR PROPOSED CHANGES IN NOPR IN RM16-22-000					**34,823 hrs.; $1,670,766 (reduction)**

Titles: FERC-725G6 (Mandatory Reliability Standard PRC-027-1) and FERC-725Y (Mandatory Reliability Standards: Operations Personnel Training (PER–005–2 and PER-006-1).

Action: Revision to existing collections and proposed new information collection.

OMB Control Nos.: to be determined (FERC-725G6)[51] and 1902-0279 (FERC-725Y).

[51] OMB will assign a Control No. when it issues a decision.

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: Annual recordkeeping and reporting requirements, with some reporting requirements being at least once every six years.

Necessity of the Information: Proposed Reliability Standards PRC-027-1 and PER-006-1 set forth requirements for coordination of protection systems and personnel training on specific topics essential to reliability. The Commission proposes to approve proposed Reliability Standards PRC-027-1 and PER-006-1, which will replace Commission-approved Reliability Standard PRC-001-1.1(ii). The proposed Reliability Standards PRC-027-1 and PER-006-1 improve upon the existing Reliability Standard PRC-001-1.1(ii) because the proposed Reliability Standards assign responsibilities to entities with more appropriate resources and skill sets to conduct studies required to coordinate protection systems. The proposed Reliability Standards also provide additional clarity to the applicable entities.

Internal review: The Commission has assured itself, by means of its internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

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

31. Comments concerning the information collection proposed in this Notice of Proposed Rulemaking and the associated burden estimates should be sent to the

Commission in this docket and may also be sent to the Office of Management and Budget, Office of Information and Regulatory Affairs [Attention: Desk Officer for the Federal Energy Regulatory Commission]. For security reasons, comments should be sent by e-mail to OMB at the following e-mail address: oira_submission@omb.eop.gov. Please refer to OMB Control Nos. to be determined (FERC-725G6) and 1902-0279 (FERC-725Y) in your submittal.

IV. Environmental Analysis

32. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[52] The action proposed here falls within the categorical exclusion in the Commission's regulations for rules that are clarifying, corrective or procedural, for information gathering, analysis, and dissemination.[53]

V. Regulatory Flexibility Act

33. The Regulatory Flexibility Act of 1980 (RFA) generally requires a description and analysis of proposed rules that will have significant economic impact on a substantial number of small entities.[54] The Small Business Administration (SBA) defines which

[52] *Regulations Implementing the National Environmental Policy Act of 1969*, Order No. 486, FERC Stats. & Regs. ¶ 30,783 (1987) (cross-referenced at 41 FERC ¶ 61,284).

[53] 18 CFR 380.4(a)(2)(ii).

[54] 5 U.S.C. 601-612.

utilities are small businesses based on the number of employees that a utility and its affiliates employ.[55]

34. The proposed Reliability Standard PRC-027-1 (included in FERC-725G6) will apply to approximately 1,612 entities (334 transmission owners, 913 generator owners, and 365 distribution providers) in the United States.[56] Pursuant to SBA regulations, the employment threshold for transmission is 500 employees, for generator owners is between 250 and 750 employees (depending on the fuel source), and for distribution providers is 1,000 employees. We estimate that the annual cost for each entity will be $1,048 for each generator owner and distribution provider and $5,507 for each transmission owner.

35. The proposed Reliability Standard PER-006-1 (included in FERC-725Y) will apply to approximately 875 generator operators in the United States. Pursuant to SBA regulations the employment threshold for generator operators is between 250 and 750 employees (depending on the fuel source). We estimate that the annual cost for each generator operator will be $719.

36. In addition, this Notice of Proposed Rulemaking proposes the retirement of Reliability Standard PRC-001-1.1(ii) (included in FERC-725A). That retirement would decrease the annual estimated cost for 875 generator operators by $4,585 each, for 177

[55] 13 CFR 121.201, Subsector 221.

[56] Many respondents serve multiple roles in the NERC compliance registry, so there is likely double counting in the estimates.

transmission operators by $6,681 each, and for 99 balancing authorities by $2,885 each. For the generator operators affected by this retirement and the proposed Reliability Standard PER-006-1, the net annual effect would be a decrease of $3,866 each. We estimate the net annual cost of this Notice of Proposed Rulemaking would vary, by type of entity, from an annual decrease of $6,681 (for each transmission operator) to an annual increase of $5,507 (for each transmission owner). We view this as a minimal economic impact for each entity. Accordingly, we certify that the proposed Reliability Standards PRC-027-1 and PER-006-1 and retirement of Reliability Standard PRC-001-1.1 (ii) will not have a significant economic impact on a substantial number of small entities.

VI. Comment Procedures

37. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due [**INSERT DATE 60 days after publication in the FEDERAL REGISTER]**]. Comments must refer to Docket No. RM16-22-000, and must include the commenter's name, the organization they represent, if applicable, and their address in their comments.

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

39. Commenters that are not able to file comments electronically must send an original of their comments to: Federal Energy Regulatory Commission, Secretary of the Commission, 888 First Street NE, Washington, DC, 20426.

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

VII. Document Availability

41. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (http://www.ferc.gov) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington, DC 20426.

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

43. User assistance is available for eLibrary and the Commission's website during normal business hours from the Commission's Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or e-mail at ferconlinesupport@ferc.gov, or the Public Reference

Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By direction of the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

161 FERC ¶ 61,131
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, and Robert F. Powelson.

North American Electric Reliability Corporation Docket No. RR17-7-000

ORDER ACCEPTING 2018 BUSINESS PLANS AND BUDGETS

(Issued November 1, 2017)

1. On August 23, 2017, the North American Electric Reliability Corporation (NERC) filed 2018 business plans and budgets for NERC, each Regional Entity,[1] and the Western Interconnection Regional Advisory Body (WIRAB) (collectively, NERC Application). For the reasons discussed below, we accept the 2018 business plans and budgets of NERC, the Regional Entities, and WIRAB, as well as the associated attachments and updates, and authorize issuance of billing invoices to fund the fiscal year 2018 operations of NERC, the Regional Entities, and WIRAB.

I. Background

A. Regulatory History

2. Section 215 of the Federal Power Act (FPA) requires the Commission to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, subject to Commission review and approval.[2] In July 2006, the Commission certified NERC as the ERO.[3]

[1] The eight Regional Entities are Florida Reliability Coordinating Council; Midwest Reliability Organization; Northeast Power Coordinating Council, Inc.; ReliabilityFirst Corporation; SERC Reliability Corporation; Southwest Power Pool Regional Entity; Texas Reliability Entity; and Western Electricity Coordinating Council (WECC).

[2] 16 U.S.C. § 824o (2012).

[3] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030,

3. Section 215(c)(2)(B) of the FPA provides that the ERO must have rules that "allocate equitably reasonable dues, fees, and other charges among end users for all activities under this section."[4] On February 3, 2006, the Commission issued Order No. 672 to implement the requirements of section 215 of the FPA, which generally provides for Commission authorization of funding for "statutory" functions conducted by the ERO, the Regional Entities, and WIRAB (i.e., those functions carried out pursuant to section 215 of the FPA).[5] Among other things, Order No. 672 established requirements for funding the ERO and approval of an ERO business plan and budget.[6] Moreover, the Commission's regulations require the ERO to file with the Commission the ERO's proposed annual budget for statutory and non-statutory activities 130 days before the beginning of the ERO's fiscal year.[7] Further, the ERO's filing must contain the annual budgets of each Regional Entity for statutory and non-statutory activities and provide supporting materials, including the ERO's and each Regional Entity's complete business plan and budget and organizational chart. The filing must also explain the proposed collection of all dues, fees, and charges, as well as the proposed expenditure of funds collected.

B. NERC Application

4. The NERC Application contains NERC's proposed business plan and budget for the year ending December 31, 2018, as well as the proposed business plans and budgets of each of the eight Regional Entities and WIRAB for the year ending December 31, 2018.

5. NERC states that it prepared its 2018 business plan and budget, and worked with the Regional Entities in developing their business plans and budgets, through a rigorous process that provided ample opportunity for review and input by the NERC Board of Trustees Finance and Audit Committee and stakeholders. According

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order on clarification and reh'g, 119 FERC ¶ 61,046 (2007), *aff'd sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009).

[4] 16 U.S.C. § 824o(c)(2)(B).

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

[6] Order No. 672, FERC Stats. & Regs. ¶ 31,204 at P 197.

[7] 18 C.F.R. § 39.4(b) (2017).

to NERC, successive versions of the 2018 business plans and budgets were discussed by the Finance and Audit Committee as well as the full NERC Board of Trustees, in meetings and conference calls, with each event providing opportunities for stakeholders to comment.[8]

6. NERC states that the proposed assessment for the total ERO (i.e., NERC, the Regional Entities, and WIRAB) for 2018 allocable to the United States is $162,112,131, which includes $56,968,506 for NERC funding; $104,544,752 for Regional Entity funding; and $598,873 for WIRAB funding.[9] NERC explains that it will continue to allocate costs to end users in the United States based on net energy for load. NERC maintains that its proposed total United States net funding requirement for the ERO enterprise is equivalent to $0.0000407 per kWh, based on the aggregate net energy for load of the United States in 2016.[10]

7. In addition to the NERC, Regional Entity, and WIRAB business plans and budgets, the NERC Application contains various attachments including: Discussion of Comments Received During Development of NERC's 2018 Business Plan and Budget (Attachment 12); Calculation of Adjustments for the Alberta Electric System Operator, Ontario Independent Electric System Operator, New Brunswick, and Quebec 2018 NERC Assessments (Attachment 13); Metrics Comparing Regional Entity Operations Based on the 2018 Budgets (Attachment 14); and Metrics on NERC and Regional Entity Administrative (Indirect) Costs Based on the 2017 and 2018 Budgets (Attachment 15).

II. Notice and Responsive Pleadings

8. Notice of NERC's August 23, 2017 filing was published in the *Federal Register*, 82 Fed. Reg. 41,400 (2017), with interventions and protests due on or before September 13, 2017. No motions to intervene were filed.

9. On August 29, David Bardin (Mr. Bardin) filed comments noting that in his prior comments submitted to NERC as part of the budget development process, he suggested that NERC should provide additional funding for its geomagnetic disturbance (GMD) research. Mr. Bardin requests that the Commission require NERC to submit quarterly reports detailing NERC's progress in its GMD research.

[8] NERC Application at 3.

[9] *Id.*, Attachment 1 (Summary Tables for NERC and Regional Entity Proposed 2018 Budgets and Assessments) at 2.

[10] *Id.* at 28.

III. Discussion

A. NERC Business Plan and Budget

10. NERC states that its 2018 business plan and budget is based on the following program areas: (1) Reliability Standards; (2) Compliance Monitoring and Enforcement and Organization Registration and Certification; (3) Reliability Assessment and System Analysis; (4) Reliability Risk Management, which is comprised of Situation Awareness, Event Analysis, and Performance Analysis; (5) Electricity Information Sharing and Analysis Center (E-ISAC), including the Cyber Risk Information Sharing Program (CRISP); and (6) Training, Education, and Personnel Certification.[11] For these program areas, NERC describes each program, identifies the program's goals and objectives, and provides the current number of full-time equivalent employees (FTEs), as well as the FTEs budgeted for 2018. NERC also provides 2017 accepted budget data and 2017 year-end projected data for comparison to the 2018 proposed budget data.

11. NERC's proposed total funding requirement for 2018 is $72,981,221, which is an increase of $2,829,561 (4.0 percent) over NERC's 2017 total funding requirement of $70,151,660.[12] NERC's proposed 2018 net funding requirement is $62,936,968 (i.e., the total funding requirement less $10,044,253 in funding from other sources), of which $56,968,506 is allocated to the United States.[13]

12. NERC states that the proposed 2018 business plan and budget reflects a provision for working capital and operating reserve funding in the amount of $77,458.[14] Finally,

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[11] *Id.* at 7-8.

[12] *Id.* at 16. NERC also states that its 2018 budget, excluding E-ISAC costs, is 0.4 percent higher than its 2017 budget excluding E-ISAC costs, while the 2018 budget for the E-ISAC is $3,335,256 (18.0 percent) higher than its 2017 budget for the E-ISAC. *Id.*

[13] *Id.* at 16-17, Attachment 2 (NERC Proposed 2018 Business Plan and Budget) at 5. NERC's other funding sources are penalty payments, third-party funding for CRISP, revenue from services and software, testing and workshop fees, and interest. *Id.* at 16-17.

[14] *Id.* at 16.

NERC proposes a 2018 staffing level of 199.29 FTEs, an increase of 9.40 FTEs from 2017 budget staffing levels.[15]

13. NERC states that it received $500,000 in penalty monies for the period of July 1, 2016 through June 30, 2017.[16] In accordance with the Commission's June 18, 2015 order,[17] and pursuant to section 1107.4 of the NERC Rules of Procedure, NERC requests an exception to section 1107.2 of the NERC Rules of Procedure to permit it to deposit the $500,000 of penalty monies into its assessment stabilization reserve. NERC also requests approval to use $600,000 of funds from the assessment stabilization reserve to reduce 2018 assessments. NERC states that these actions will leave a balance of $1,571,000 in the assessment stabilization reserve for use to offset and stabilize assessments in future years' budgets.[18]

Commission Determination

14. We accept NERC's 2018 business plan and budget. We find that NERC's 2018 budget is reasonable and that the associated costs of NERC's jurisdictional functions are equitably allocated among end users in the United States. Additionally, based on the details provided by NERC in its application, we grant NERC's request for an exception under section 1107 of the NERC Rules of Procedure, allowing NERC to allocate $500,000 in penalty monies to its assessment stabilization reserve, and approve the withdrawal of $600,000 from the assessment stabilization reserve (i.e., a net withdrawal of $100,000). We note that the decision here is limited to this case. Any future requests for an exception to section 1107.2 of the NERC Rules of Procedure will be addressed based on the facts at that time.

15. We determine not to require NERC to submit quarterly reports on progress regarding GMD research, as requested by Mr. Bardin, as this request is beyond the scope of this proceeding. However, we note that the Commission recently required NERC to submit a final, or otherwise updated, GMD Work Plan within six months of the date of issuance of the recent order in Docket No. RM15-11-002 and to continue to provide

[15] *Id.*, Attachment 2 at 18.

[16] *Id.* at 43-44.

[17] *North American Electric Reliability Corp.*, 151 FERC ¶ 61,225, at P 19 (2015).

[18] NERC Application at 43-44.

informal progress updates with Commission staff.[19] We also note that NERC may submit a supplemental budget request if it finds that additional funds are necessary to meet its statutory mission.[20]

B. Regional Entity Business Plans and Budgets

16. NERC's Application includes the 2018 business plans and budgets of each Regional Entity. The proposed total assessment for the Regional Entities that is allocable to the United States is $104,544,752, which represents a $4,798,178 (4.8 percent) increase from 2017.[21] NERC states that it reviewed the Regional Entity business plans and budgets and concludes that each Regional Entity proposes necessary and adequate resources to carry out its delegated functions.[22]

Commission Determination

17. We find that each Regional Entity submission reasonably supports the level of expenditures identified in their respective budgets and that each Regional Entity is focused on adequately staffing and funding all of their respective program areas to perform the delegated, statutory functions. Accordingly, we accept the Regional Entity business plans and budgets.

C. WIRAB Business Plan and Budget

18. WIRAB proposes statutory expenses of $1,067,785 in 2018, which is a $161,295 (13.1 percent) decrease from its 2017 budget.[23] To fund its operations in 2018, WIRAB proposes a statutory assessment of $711,026, of which $598,873 would be allocable to end users in the United States.[24]

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[19] *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 161 FERC ¶ 61,048 (2017).

[20] 18 C.F.R. § 39.4(d) (2017).

[21] NERC Application at 22, Attachment 1 at 2.

[22] *Id.* at 48.

[23] *Id.* at 66.

[24] *Id.*, Attachment 11 (Western Interconnection Regional Advisory Body Proposed 2018 Business Plan and Budget) at 3.

19. WIRAB notes that its proposed key activities in 2018 include the following: (1) advising WECC on the implications of high levels of deployment of solar photovoltaic generation on the reliable operation of the bulk electric system; (2) advising WECC on interdependencies between the natural gas and electric industries in the West and the implications for the reliable operation of the bulk electric system; (3) encouraging WECC to systematically assess the availability of Essential Reliability Services under a wide-range of future resource scenarios; and (4) encouraging the Member Advisory Committees at WECC and Peak Reliability to increase their focus on emerging reliability issues and to improve their processes for advising the Boards of Directors of WECC and Peak Reliability.[25] WIRAB's budget includes 5.5 FTEs for 2018, which is the same as in its 2017 budget.[26]

Commission Determination

20. Based on the information provided in the instant filing, we conclude that WIRAB's 2018 business plan and budget is reasonable and, accordingly, we accept WIRAB's 2018 business plan and budget.

The Commission orders:

(A) NERC's 2018 business plan and budget is hereby accepted.

(B) The Regional Entities' 2018 business plans and budgets are hereby accepted.

(C) WIRAB's 2018 business plan and budget is hereby accepted.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[25] *Id.*, Attachment 11 at 8-15.

[26] *Id.*, Attachment 11 at 15.

161 FERC ¶ 61,187
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Cheryl A. LaFleur, and Robert F. Powelson.

North American Electric Reliability Corporation Docket No. RR15-2-005

ORDER ON COMPLIANCE FILING

(Issued November 16, 2017)

1. On February 21, 2017, the North American Electric Reliability Corporation (NERC) submitted an annual filing on its Compliance Monitoring and Enforcement Program (CMEP), in accordance with the Commission's prior orders approving NERC's Reliability Assurance Initiative (RAI).[1] In addition to providing the required annual report on the program, NERC requests Commission approval of two proposed program changes: (1) elimination of the public posting of compliance exceptions identified through self-logging; and (2) expansion of the use of compliance exceptions to include certain moderate risk violations.

2. The Commission accepts NERC's 2016 ERO Enterprise Compliance Monitoring and Enforcement Program Annual Report (2016 CMEP Report or Report). However, for the reasons discussed below, the Commission denies NERC's request for approval of two proposed changes to the CMEP: eliminating the public posting of compliance exceptions identified through self-logging and expanding the use of compliance exceptions to include certain moderate risk noncompliance.

I. Background

A. Section 215 of the Federal Power Act

3. Section 215(c) of the Federal Power Act (FPA) requires the Commission to certify an Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, as well as rules to provide fair and impartial procedures for

[1] *North American Electric Reliability Corp.*, 150 FERC ¶ 61,108, at PP 2, 49-52 (RAI Order); *order on compliance*, 153 FERC ¶ 61,130 (2015) (RAI Compliance Order).

enforcement of such Reliability Standards, subject to Commission review and approval.[2] This statutory requirement is reflected in section 39.3 of the Commission's regulations.[3] In addition, section 215(f) of the FPA requires the ERO to file with the Commission for approval of any proposed rule or proposed rule change.[4]

B. NERC Compliance Monitoring and Enforcement

4. On February 3, 2006, the Commission issued Order No. 672 to implement the requirements of section 215 of the FPA governing electric reliability.[5] On July 20, 2006, the Commission certified NERC as the ERO, including approval of the NERC Rules of Procedure addressing, among other things, NERC's CMEP.[6] The intent of the ERO compliance program, as noted by the Commission, is to facilitate the "ongoing monitoring of user, owner and operator compliance with Reliability Standards."[7] The Commission specified that the three required components of an ERO compliance program are: (1) a compliance program that includes proactive compliance audits; (2) an investigation program for alleged violations of Reliability Standards that includes prompt Commission notification of incidents and their dispositions; and (3) a penalty program.[8]

5. On March 15, 2012, the Commission issued an order accepting, with conditions, NERC's petition requesting approval of the Find, Fix and Track (FFT) program, allowing NERC to address lesser-risk, remediated possible violations of Reliability Standards

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[2] 16 U.S.C. § 824o(c)(2)(C) (2012).

[3] 18 C.F.R. § 39.3 (2017).

[4] 16 U.S.C. § 824o(f).

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

[6] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062, at P 299, *order on reh'g and compliance*, 117 FERC ¶ 61,126 (2006), *order on compliance*, 118 FERC ¶ 61,030, *order on compliance*, 118 FERC ¶ 61,190, *order on clarification and reh'g*, 119 FERC ¶ 61,046 (2007), *rev. denied sub nom. Alcoa Inc. v. FERC*, 564 F.3d 1342 (D.C. Cir. 2009). The CMEP is Appendix 4C to the NERC Rules.

[7] *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 at P 293.

[8] *Id.* (citing Order No. 672, FERC Stats. & Regs. ¶ 31,204).

through FFT spreadsheet informational filings as opposed to the formal Notice of Penalty process.[9]

6. On December 20, 2012, the Commission issued an order pursuant to FPA section 215(f) conditionally approving revisions to the NERC Rules of Procedure.[10] Among the revisions approved in the December 20 Order was a proposal to revise CMEP section 5.0 and Sanction Guidelines section 2.2, to grant NERC the flexibility to deviate from the standard CMEP procedures so that other approaches to enforcement could be considered and applied where the circumstances warranted such flexibility.[11] In approving NERC's proposed revision, the Commission explained that the new flexibility should be used in "limited circumstances" as a reasonable exercise of NERC's enforcement discretion.[12]

7. On June 20, 2013, the Commission issued an order accepting NERC's first annual FFT report and approving five enhancements to the FFT program.[13] On September 18, 2014, the Commission issued an order accepting NERC's second FFT annual report, as well as approving the expansion of the FFT program to moderate risk possible violations that meet certain Commission-approved criteria.[14] In approving the expansion of the FFT program, the Commission recognized the efficiencies that had resulted from the FFT program, but the Commission also highlighted situations where NERC and the Regional

[9] *North American Electric Reliability Corp.*, 138 FERC ¶ 61,193; *order on reh'g*, 139 FERC ¶ 61,168 (2012).

[10] *North American Electric Reliability Corp.*, 141 FERC ¶ 61,241 (2012) (December 20 Order).

[11] NERC's Sanction Guidelines, Appendix 4B to the NERC Rules, sets forth procedures to be followed and factors that will be considered when the ERO, and the Regional Entities to which the Commission has approved the ERO's delegation of enforcement authority, determine penalties or sanctions for violations.

[12] December 20 Order, 141 FERC ¶ 61,241 at P 95.

[13] *North American Electric Reliability Corp.*, 143 FERC ¶ 61,253 (2013) (June 20 Order).

[14] *North American Electric Reliability Corp.*, 148 FERC ¶ 61,214, at PP 3-4 (2014) (the expansion of the FFT program to certain moderate risk possible violations followed a pilot program approved by the Commission in the June 20 Order).

Entities could improve the risk assessments underlying FFT treatment and provide greater clarity in the information provided to support FFT treatment.[15]

8. On February 19, 2015, the Commission issued an order approving, with certain conditions, NERC's Reliability Assurance Initiative, designed to transition NERC to a risk-based approach to both compliance monitoring and enforcement.[16] The Commission approved the two primary components of NERC's risk-based approach to enforcement: (1) a compliance exception process intended to identify minimal risk instances of noncompliance, to be recorded and mitigated without triggering a formal enforcement action; and (2) a voluntary self-logging program, which would allow pre-screened registered entities to self-identify, assess, and mitigate minimal risk instances of noncompliance, to be periodically rather than individually reviewed by the Regional Entity and presumptively processed as compliance exceptions. The Commission directed NERC to make certain modifications in those programs, however, requiring NERC to publicly post compliance exceptions in a manner similar to its FFT postings; requiring some level of formal review of an entity's internal controls before allowing participation in the self-logging program; and requiring NERC to include certain additional information in its annual report on the RAI.[17] The Commission accepted NERC's compliance filings in response to the RAI Order, subject to certain conditions, on November 4, 2015.[18]

II. NERC's Annual Report and Proposed RAI Enhancements

9. NERC submitted its annual CMEP compliance filing on February 21, 2017 (February 21 Compliance Filing), including the 2016 CMEP Report as an attachment. In the 2016 CMEP Report, NERC describes the key activities that occurred in 2016 and reviews the progress of its risk-based CMEP. Among other things, the 2016 CMEP Report indicates that compliance exceptions continue to be the dominant disposition method for noncompliance that poses a minimal risk to the reliability of the Bulk-Power System, and that the FFT program is used primarily to resolve moderate risk noncompliance that does not warrant a penalty and is otherwise suitable for streamlined treatment. With respect to the self-logging program, the 2016 CMEP Report states

[15] *Id.* PP 28, 30.

[16] RAI Order, 150 FERC ¶ 61,108.

[17] *Id.* PP 36-39, 41-43, 49-52.

[18] RAI Compliance Order, 153 FERC ¶ 61,130; *see also North American Electric Reliability Corp.*, Docket No. RR15-2-004 (May 4, 2016) (letter order accepting changes to NERC Rules of Procedure as required in RAI Compliance Order).

that 59 registered entities have been approved to participate in the program as of December 31, 2016. The Report also indicates that the majority of Regional Entities are consistently implementing the self-logging program, and that self-logging instances of noncompliance reduces processing times by two-thirds when compared with self-reporting.[19]

10. In addition to seeking acceptance of the 2016 CMEP Report, and based on the results of NERC's oversight activities for the program, NERC also requests that the Commission approve two enhancements to the program. First, NERC proposes to eliminate the public posting of compliance exceptions identified through self-logging. Second, NERC proposes to expand the use of compliance exceptions to include certain moderate risk noncompliance, most of which are currently processed as FFTs.

A. Self-Logging Program

11. As NERC explains in the February 21 Compliance Filing, the self-logging program currently allows an eligible registered entity to log minimal risk noncompliance for subsequent review by the Compliance Enforcement Authority (i.e., the Regional Entity) in lieu of submitting an individual self-report for each noncompliance or potential noncompliance.[20] Self-logged items are limited to those that pose a minimal risk to reliability and, subject to the Regional Entity's review, are presumptively processed as compliance exceptions.[21]

12. NERC explains that, as originally envisioned, the self-logging program was designed to achieve three primary goals: (1) promote the development of strong internal controls to identify, assess, and correct noncompliance; (2) enhance visibility into registered entities' internal controls to identify, assess, and correct minimal risk noncompliance; and (3) increase efficiencies for NERC, Regional Entities, and registered entities through a streamlined processing and resolution of nonpublic minimal risk noncompliance.[22] NERC states that it viewed confidentiality as a key feature of the program when it was first proposed, maintaining that "the non-public disposition of noncompliance was at once an incentive for participation but also a way to refocus the

[19] 2016 CMEP Report at 13.

[20] February 21 Compliance Filing at 4. Participants are admitted to the self-logging program upon a formal review of internal controls related to their ability to identify, assess, and correct noncompliance.

[21] *Id.* at 5-6.

[22] *Id.* at 4.

attention of the public to enforcement actions which address violations posing greater risk to the [Bulk-Power System]."[23] NERC maintains that the Commission "unintentionally removed an incentive for registered entities to participate in the program" when it required logged noncompliance to be posted publicly, and that this requirement has reduced interest in the program.[24]

13. As a result, NERC contends, the benefits of the program, such as the possible expansion of the ERO Enterprise's visibility into entities' internal controls to identify, assess, and correct noncompliance, have been reduced.[25] Furthermore, NERC maintains that the public posting requirement has potentially tempered registered entities' inclination to include "near misses" in logs. Finally, NERC asserts that the public posting requirement has reduced the efficiency benefits of the program, due to the time required for participants to prepare their logs for public disclosure, and has limited the opportunity for the ERO Enterprise and registered entities to engage in robust trending discussions.[26]

14. NERC maintains that while the self-logging program provided some positive impacts on reliability, for example, by requiring formal review of an entity's internal controls before being granted the ability to self-log, the public posting requirement of the program has discouraged participation.[27] Based on its assessment of the self-logged noncompliance posted on NERC's website to date, NERC concludes that the educational value the public could derive from the review of individual logged items is limited.[28] NERC expresses concern that publicly posting self-logged noncompliance could potentially divert the public's attention from the review of higher risk matters, including those routinely processed as Notices of Penalty, and NERC also notes that self-logged

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[23] *Id.* at 10.

[24] *Id.* at 4.

[25] *Id*. In support of its position, NERC states that "nearly all the Regional Entities had received feedback from registered entities that the required public posting of self-logs has led to a lack of continued interest in the Self-Logging Program," and that the posting requirement "appears to have limited incentives for [participants] because it effectively results in treating the processing of self-logs no differently than other lesser risk issues." *Id.* at 11.

[26] *Id*. at 4.

[27] *Id.* at 11.

[28] *Id.* at 12.

noncompliance will still be subject to oversight by the Commission as well as NERC. NERC also contends that making self-logs non-public can only encourage more open and full communication between registered entities and Regional Entities.[29]

15. Instead of public posting, NERC proposes to include all self-logged noncompliance in a separate confidential spreadsheet, similar to the non-redacted Critical Infrastructure (CIP) compliance exceptions currently provided to the Commission.[30] NERC further proposes to prepare an anonymized annual summary of self-logged noncompliance, to be included in its CMEP annual reports. According to NERC, these summaries would generally describe the noncompliance identified in the logs; common themes in root cause and risk; and successful mitigation strategies used to address those causes and risk. NERC asserts that these summaries would provide more useful information regarding noncompliance, risk, and mitigation than stakeholders currently receive from simply listing the individual self-logged compliance exceptions.

16. Additionally, NERC states that it would begin posting on its website a list of entities admitted to the self-logging program. NERC maintains that providing a list of such high-performing entities would provide an additional incentive for registered entities to request admission to the program and an additional level of transparency to the public.

B. Expansion of Compliance Exceptions Program

17. With respect to the expansion of the compliance exceptions program to include certain moderate risk noncompliance, NERC proposes criteria for determining which moderate risk noncompliance would be eligible for compliance exception treatment that mirror the criteria currently used for determining FFT eligibility. As is currently done for moderate risk noncompliance being considered for FFT treatment, the Regional Entity would consider the underlying facts and circumstances of the noncompliance, including what happened, why, when, and where. The Regional Entity would also consider: (1) the level of risk to reliability; (2) the registered entity's internal compliance program – including preventative and corrective processes and procedures, management practices that self-identify noncompliance, and commitment to compliance; (3) aggravating factors such as a history of repeat noncompliance;[31] and (4) any "above and beyond" mitigating

[29] *Id.* at 13.

[30] *Id.*

[31] NERC states that it would not consider it appropriate, at this time, to treat a moderate risk noncompliance incident with aggravating compliance history as a compliance exception. *Id.* at 17.

measures.[32] NERC states that these criteria would facilitate recognition of those registered entities with strong management practices that self-identify noncompliance, and would provide clear incentives for other registered entities to self-report and improve their management practices. NERC describes this proposed expansion of the compliance exceptions program as "the next logical step in the evolution of the program,"[33] and indicates that it may reconsider the continued need for the FFT program after it gains additional experience with moderate risk compliance exceptions.[34]

18. Although NERC acknowledges that prior noncompliance processed as a compliance exception is not considered an aggravating factor for penalty purposes, NERC indicates that it would continue to consider such noncompliance as a part of a registered entity's overall risk profile.[35]

19. Finally, NERC states that implementation of the proposed changes to the CMEP may require changes to the NERC Rules of Procedure. NERC states it will develop and submit a filing requesting approval for such changes upon Commission approval of the proposed changes, or as otherwise directed by the Commission.

III. Notice of Filing, Interventions, and Comments

20. Notice of NERC's February 21 Compliance Filing was issued on February 22, 2017 and published in the Federal Register, 82 Fed. Reg. 12,578 (March 6, 2017), with comments due on or before March 14, 2017. The following entities filed timely comments and timely motions to intervene, or had previously intervened in the underlying proceeding: Edison Electric Institute (EEI); PPL Electric Utilities Corporation (PPL); American Electric Power Service Corporation (AEP); and American Public Power Association, Electricity Consumers Resource Council, National Rural Electric Cooperative Association, and Transmission Access Policy Study Group, filing collectively as Joint Commenters. ISO/RTO Council and MISO Transmission Owners filed motions to intervene and comments out-of-time.

21. All commenters support NERC's proposal to expand the compliance exceptions program to include moderate risk noncompliance, as described in NERC's filing. All

[32] *Id.* at 5-6, 16-17.

[33] *Id.* at 16.

[34] *Id.* at 6.

[35] *Id.* at 17.

commenters except Joint Commenters support NERC's proposal to allow for non-public resolution of self-logged noncompliance, as further discussed below.

IV. Discussion

22. The timely, unopposed motions to intervene are granted pursuant to the operation of Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2017). We also grant the untimely motions to intervene, given the parties' interest in the proceeding, the early stage of the proceeding, and the absence of undue delay or prejudice to any other party.[36]

23. We accept NERC's 2016 CMEP Report, filed in accordance with the requirements of the prior RAI and RAI Compliance Orders. We further find that requiring NERC to make a separate, annual informational filing as described in the RAI Order[37] is no longer necessary and terminate that requirement, provided that NERC: (1) continues to include compliance exceptions in the annual "sampling" filing it makes pursuant to the FFT Order,[38] and (2) continues to include information on the RAI program, including observed trends and examples of matters treated as compliance exceptions, in the CMEP Report prepared for NERC's Board of Trustees Compliance Committee. While we will also no longer require NERC to include any proposed enhancements to its RAI program as part of this annual filing, we continue to encourage NERC to propose program enhancements, and note that such enhancements or expansions should be filed for Commission approval, accompanied by relevant supporting data.

24. As further discussed below, we deny NERC's request for approval of the two proposed changes to its CMEP because, in most situations, information on NERC's resolution of compliance and enforcement matters should be transparent and publicly

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[36] *See* 18 C.F.R. § 385.214(d).

[37] *See* RAI Order, 150 FERC ¶ 61,108, at PP 49-52. In its first annual filing pursuant to the RAI Order, NERC provided additional information on the RAI program as directed by the Commission in paragraphs 50-52 of the RAI Order. That informational filing was accepted by delegated letter order. *See North American Electric Reliability Corp.*, Docket No. RR15-2-004 (May 4, 2016).

[38] *See* June 20 Order, 143 FERC ¶ 61,253 at P 41 (2013) (accepting NERC proposal to make an annual informational filing reporting on FFTs); *North American Electric Reliability Corp.*, Docket No. RC11-6-004 (Nov. 13, 2015 (delegated letter order accepting sampling and evaluation of compliance exceptions as part of NERC's FFT annual informational filing).

available and processing of noncompliance should reflect the relative risk level of the violation.

A. Self-Logging Program

25. EEI, PPL, ISO/RTO Council, AEP, and MISO Transmission Owners urge the Commission to approve NERC's proposed changes to the self-logging program, allowing for non-public posting of self-logged noncompliance, based on similar arguments to those made by NERC. EEI states, for example, that public posting of self-logged compliance exceptions "promotes no discernible public benefit," and believes such posting can pose security risks.[39] Like NERC, these commenters maintain that the public posting requirement discourages participation in the program, and that the treatment of noncompliance in the self-logging program is essentially the same as the treatment of other low risk violations or of self-reported violations.[40] Similarly, ISO/RTO Council contend that the low number of participants in the self-logging program, 59 out of over 1,200 registered entities, suggests that the incentives to participate in the program are inadequate.[41]

26. Joint Commenters oppose NERC's proposal to discontinue the public posting of self-logged compliance exceptions, asserting that the transparency it provides is essential to educating industry and preserving the credibility of NERC's compliance and enforcement program. Joint Commenters contend that, because compliance exceptions are a significant percentage of noncompliance, their public disclosure provides registered entities with invaluable information on how NERC and the Regional Entities interpret what is necessary to comply with the various requirements in Reliability Standards, as well as the acceptable mitigation measures.[42]

27. Joint Commenters also maintain that the public posting of all compliance exceptions could be an essential tool to help identify unnecessary or redundant

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[39] EEI Comments at 3; *see also* PPL Comments at 3; ISO/RTO Council Comments at 3-4.

[40] *Id.*; *see also* PPL Comments at 2. AEP also requests that NERC consider further improvements to the self-logging program, to ensure it confers more discernible benefits beyond those available through self-reporting. AEP recommends "improved tracking mechanisms or allowing entities to self-maintain the log internally with regional oversight." AEP Comments at 2.

[41] IRC Comments at 4.

[42] Joint Commenters' Comments at 4-5.

requirements in the Reliability Standards.[43] Finally, Joint Commenters contend that the relatively low number of entities approved to self-log does not necessarily indicate that the program lacks sufficient benefits. Instead, they point to the similarly low number of Internal Control Evaluations (ICEs) (61) conducted in 2016. Joint Commenters state that the low number of ICE reviews completed, even if "less exacting" than the review required for self-logging participation, suggests that the many registered entities that experience infrequent noncompliance are unlikely to undergo the process to qualify for self-logging, even if the incentives for participation were increased.[44]

28. We agree with Joint Commenters that the value of maintaining the transparency of self-logged noncompliance continues to outweigh the asserted benefit that might accrue from increasing the incentive to participate in the program. The Commission addressed this issue when the compliance exceptions program was first proposed, and rejected NERC's proposal to treat all compliance exceptions as non-public. The Commission found that the additional burden of public posting is minimal, and that preserving transparency in compliance and enforcement matters provides meaningful benefits, by educating industry and ensuring consistency across NERC's and the Regional Entities' compliance and enforcement programs:

> We will require NERC to publicly post compliance exceptions in a manner similar to how FFTs are currently posted. We find arguments that publicly posting compliance exceptions is unnecessary or will discourage entities from taking advantage of the efficiencies of RAI unpersuasive. Public disclosure of compliance exceptions would appear to require only minimal additional resources since information will be compiled monthly in a spreadsheet and provided to the Commission. Moreover, the Commission's requirement for NERC to publicly post FFTs does not appear to have been a burden on registered entities, as NERC states that since 2011, FFTs were used to process over 2,000 instances of non-compliance. Rather, we agree with Joint Commenters that transparency in compliance and enforcement matters is beneficial to educate industry and provide additional oversight of the ERO Enterprise. It also serves to allow interested registered entities and other parties to measure consistency across entities, classes of entities, or Regional Entities, as well as demonstrating the quality of registered

[43] *Id.* at 5.

[44] *Id.* at 7-10.

> entities' internal controls programs, particularly an entity's ability to swiftly and effectively identify, assess, and correct possible instances of noncompliance.[45]

29. NERC maintains, based on its experience over the past two years, that the self-logging program is not fulfilling its intended objectives due to the limited incentive to participate. In support of that position, NERC and other commenters point to the feedback provided to Regional Entities and the low number of participants in the program.[46] We acknowledge that the Commission must balance a number of considerations in evaluating the design and scope of the self-logging program, including the efficiency of the program, its rigor, its transparency, and the level of participation in it. However, while it may be true that interest in the self-logging program could be further enhanced if self-logged, minimal risk instances of noncompliance were not publicly posted, we remain unpersuaded that these potential increases in participation outweigh the benefits of transparency that the Commission identified in the RAI Order.[47] As of December 31, 2016, 59 registered entities were participating in the program, and the evidence provided to date indicates that these participants have found the program to be beneficial and that the program generates additional processing efficiencies. PPL, for example, describes its experience in the self-logging program as "positive" and a "privilege," and states that the program allowed PPL to "significantly reduce the amount of time devoted to reporting on minimal risk matters."[48]

30. NERC's and commenters' remaining reasons for not requiring the public disclosure of compliance exceptions are similar to arguments made in the RAI proceeding. NERC states, for example, that the requirement for public posting of self-logged noncompliance has reduced the efficiency benefits of the program and that participants have to spend extra time for preparation of self-logs that will be publicly posted.[49] However, the findings of the 2016 CMEP Report suggest that these burdens do

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[45] RAI Order, 150 FERC ¶ 61,108 at P 36 (footnote omitted). The Commission further stated that it "has maintained a consistent view with regard to transparency in compliance monitoring and enforcement matters." *Id.* P 38.

[46] *See* February 21 Compliance Filing at 11; ISO/RTO Council Comments at 4.

[47] *Supra* n. 45.

[48] PPL Comments at 2-3.

[49] February 21 Compliance Filing at 4. While NERC refers to public posting of "self-logs," *id.* at 11 and 13, NERC does not state that it publicly posts registered entities' actual "self-logs."

not eclipse the other efficiencies gained through self-logging, as the Report states that self-logging noncompliance reduces processing times by two-thirds when compared with self-reports.[50]

31. We believe that public posting of self-logged compliance exceptions continues to confer significant benefits, encouraging entities to develop and exercise stronger internal control mechanisms, and helping to prevent possible reoccurrence(s) of mitigated issues. Indeed, NERC, and the commenters that support NERC's proposal, acknowledge that the self-logging program has provided benefits. Despite NERC's general claim that the public posting requirement has reduced the efficiency benefits of the self-logging program, NERC elsewhere acknowledges that the self-logging program "resulted in increased efficiencies when compared to the processing of individual Self-Reports and other minimal risk noncompliance."[51]

32. In sum, we deny NERC's proposal to treat self-logged compliance exceptions as nonpublic, as NERC and supporting commenters have not provided sufficient justification for reconsidering the Commission's prior decision requiring public posting of all compliance exceptions. Likewise, we are not persuaded by NERC to deviate from the Commission's general policy requiring transparency in the outcome of compliance and enforcement matters relating to noncompliance with Reliability Standards.

B. Treatment of Moderate Risk Violations as Compliance Exceptions

33. As discussed above, NERC proposes to extend the compliance exceptions program to allow for the resolution of certain moderate risk violations, using criteria that it describes as similar to the criteria currently used to determine whether to process a moderate risk violation as an FFT. NERC suggests that approval of its proposal could make the FFT program obsolete, stating that "[a]fter further experience with moderate risk [compliance exceptions], the ERO Enterprise would consider the continued need for the FFT program."[52] NERC maintains that this modification aligns with NERC's end-state goals for risk-based enforcement, which "requires the flexibility of a range of tools

[50] 2016 CMEP Report at 13. NERC's current claim that "[p]ublic posting of self-logged noncompliance potentially diverts the public's attention from the review of higher risk matters" was similarly considered and rejected in the RAI Order, and we find no reason to reconsider that argument here. *See* RAI Order, 150 FERC ¶ 61,108 at PP 17, 36-39.

[51] February 21 Compliance Filing at 8.

[52] *Id.* at 6.

to prioritize and treat noncompliance based on risk and enforcement practices with clear distinctions based on risk posed to the reliability of the [Bulk-Power System]."[53]

34. All of the commenters support NERC's proposed expansion of the compliance exceptions program. EEI and other commenters agree that the criteria NERC proposes for determining when moderate level risk violations are eligible for compliance exception treatment are appropriate, and that approval of NERC's proposal will improve NERC's ability to focus its resources on issues posing a higher risk to reliability.[54]

35. We are not persuaded that the claimed efficiency gains in processing certain moderate risk violations as compliance exceptions, rather than as FFTs, are sufficient to outweigh our concerns with treating many moderate risk noncompliances through a non-enforcement track. NERC itself indicates that this expansion of the compliance exceptions program would be the first step in the potential elimination of the FFT program, and we are concerned that it would eliminate much, if not all, of the distinction between minimal and moderate risk noncompliance.

36. Given that the criteria NERC would use to determine whether a moderate risk incident should receive compliance exception treatment mirror the criteria currently used to determine whether FFT processing is appropriate, coupled with NERC's suggested review of the future need for the FFT program, it appears that all or virtually all moderate risk incidents that would have been processed through the FFT program could be processed as compliance exceptions under NERC's proposal. Thus, NERC appears to be effectively proposing a binary approach: either there is a serious/substantial risk posed by a violation, in which case it is processed through a full Notice of Penalty or spreadsheet Notice of Penalty, or, even if it is a moderate risk violation, it can be resolved as a compliance exception. As such, the violation would be processed on a non-enforcement track, would not be considered as part of the entity's compliance history (except in a few circumstances), and would not require verified mitigation completion (i.e., mitigation verification by Regional Entities along with an affidavit of mitigation completion signed by the relevant registered entity's officer or other representative). While this approach may be appropriate for minimal risk violations, NERC has not adequately justified this limited approach for moderate risk violations.

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[53] *Id.* at 17.

[54] *See* EEI Comments at 4; *see also* PPL Comments at 4-5; ISO/RTO Council Comments at 5 (maintaining that "registered entities whose compliance programs mature may still encounter potential non-compliance events with moderate risk profiles, yet effectively manage that risk through timely identification and correction worthy of streamlined processing").

37. Consistent with prior orders regarding the CMEP, the compliance response should generally reflect to some extent the difference in reliability risks between serious, moderate, and minimal risk instances of noncompliance.[55] In prior filings, NERC has indicated that "if something serious could have occurred and there were only some protections in place to reduce risk, the risk assessment would likely be moderate."[56] The Commission continues to believe that this and other moderate instances of noncompliance require appropriate mitigation and continuing oversight, which is offered through the NOP processes or the FFT program. Accordingly, we deny NERC's proposal to expand the compliance exceptions program to include certain moderate risk incidents of noncompliance. We continue to support the general direction of NERC's compliance program towards a focus on risk-based compliance and conclude that our holding today is consistent with that approach.

38. Finally, we take this opportunity to make an observation regarding the proper processing of one form of noncompliance. As part of the Commission's ongoing oversight of NERC's CMEP, Commission staff recently conducted a joint review with NERC of a sampling of FFTs and compliance exceptions processed in the 2016 fiscal year. One of the compliance exceptions reviewed involved falsification of battery testing records by a registered entity's employee. The Commission does not consider it appropriate to process instances of noncompliance involving falsification of records as compliance exceptions or FFTs. Rather, such circumstances warrant a full Notice of Penalty.[57]

The Commission orders:

(A) The Commission hereby accepts NERC's 2016 CMEP Annual Report, and terminates the annual informational filing requirement regarding the RAI program, as discussed in the body of this order.

[55] RAI Order, 150 FERC ¶ 61,108 at PP 15, 27.

[56] *Id.* P 15.

[57] *See North American Electric Reliability Corp.*, 138 FERC ¶ 61,193 at P 49 (incidents involving "intentional or willful acts or omission" warrant full Notice of Penalty treatment).

(B) The Commission hereby denies NERC's request to modify its Compliance Monitoring and Enforcement Program, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

SUNSHINE ACT MEETING NOTICE

November 9, 2017

The following notice of meeting is published pursuant to section 3(a) of the government in the Sunshine Act (Pub. L. No. 94-409), 5 U.S.C. 552b:

AGENCY HOLDING MEETING:	FEDERAL ENERGY REGULATORY COMMISSION
DATE AND TIME:	November 16, 2017 10:00 A.M.
PLACE:	Room 2C 888 First Street, N.E. Washington, D.C. 20426
STATUS:	OPEN
MATTERS TO BE CONSIDERED:	Agenda * NOTE - Items listed on the agenda may be deleted without further notice.
CONTACT PERSON FOR MORE INFORMATION:	Kimberly D. Bose Secretary Telephone (202) 502-8400 For a recorded message listing items struck from or added to the meeting, call (202) 502-8627.

This is a list of matters to be considered by the Commission. It does not include a listing of all documents relevant to the items on the agenda. All public documents, however, may be viewed on line at the Commission's website at http://www.ferc.gov using the eLibrary link, or may be examined in the Commission's Public Reference Room.

1037TH - MEETING

REGULAR MEETING

November 16, 2017

10:00 AM

Item No	Docket No.	Company
		ADMINISTRATIVE
A-1	AD18-1-000	Agency Administrative Matters
A-2	AD18-2-000	Customer Matters, Reliability, Security and Market Operations
A-3	AD07-13-011	2017 Report on Enforcement
		ELECTRIC
E-1	RM16-22-000	Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards
E-2	RR15-2-005	North American Electric Reliability Corporation
E-3	ER13-75-011 ER15-416-001	Public Service Company of Colorado
	ER13-77-010 ER15-433-001	Tucson Electric Power Company
	ER13-78-011 ER15-434-001	UNS Electric, Inc.
	ER13-79-009 ER15-413-001	Public Service Company of New Mexico
	ER13-82-009 ER15-411-006	Arizona Public Service Company
	ER13-91-008 ER15-426-001	El Paso Electric Company
	ER13-96-009 ER15-431-001	Black Hills Power, Inc.
	ER13-97-009 ER15-430-001	Black Hills Colorado Electric Utility Company, LP
	ER13-105-005 ER15-423-001 ER15-428-003	NV Energy, Inc. Nevada Power Company
	ER15-424-001	Sierra Pacific Power Company
	ER13-120-009 ER15-432-001	Cheyenne Light, Fuel, & Power Company

E-4	ER17-1310-001	New York Independent System Operator, Inc.
E-5	ER15-572-000 ER15-572-002 ER15-572-006	New York Independent System Operator, Inc.
E-6	ER16-120-001 ER16-120-003 EL15-37-002	New York Independent System Operator, Inc.
E-7	ER17-2362-000	PJM Interconnection, L.L.C.
E-8	ER17-249-001	PJM Interconnection, L.L.C.
E-9	ER17-528-000 ER17-528-001	PJM Interconnection, L.L.C.
E-10	ER17-1269-000	FirstEnergy Solutions Corp.
E-11	ER17-1272-000 ER17-1559-000	FirstEnergy Solutions Corp.
E-12	ER17-889-000	Southwest Power Pool, Inc.
E-13	ER17-1482-000	Southwest Power Pool, Inc.
E-14	ER17-1160-000 ER17-1160-001	Entergy Arkansas, Inc.
E-15	ER10-1350-006	Entergy Services, Inc.
E-16	ER17-897-000	Entergy Louisiana, Inc.
E-17	EL09-61-006	Louisiana Public Service Commission v. Entergy Corporation, Entergy Services, Inc., Entergy Louisiana, L.L.C., Entergy Arkansas, Inc., Entergy Mississippi, Inc., Entergy New Orleans, Inc., Entergy Gulf States Louisiana, L.L.C. and Entergy Texas, Inc.
E-18	ER17-1221-000	NorthWestern Corporation
E-19	ER17-1014-000	Midcontinent Independent System Operator, Inc.
E-20	ER16-938-005 ER16-938-006	Arizona Public Service Company
E-21	ER17-558-000	Louisville Gas and Electric Company
E-22	ER17-1386-000	Bishop Hill Energy LLC
E-23	EL16-78-001 QF90-203-008	Saguaro Power Company, A Limited Partnership
E-24	EL17-74-000 QF90-73-009	EF Kenilworth LLC

E-25	EL16-112-001	Coalition of MISO Transmission Customers v. Midcontinent Independent System Operator, Inc.
	ER17-892-000	Midcontinent Independent System Operator, Inc.
E-26	EL17-13-000	American Municipal Power, Inc., Blue Ridge Power Agency, Craig-Botetourt Electric Cooperative, Indiana Michigan Municipal Distributors, Association, Indiana Municipal Power Agency, Old Dominion Electric Cooperative, Inc., Wabash Valley Power Association, Inc. v. Appalachian Power Company, Columbus Southern Power Company, Indiana Michigan Power Company, Kentucky Power Company Kingsport Power Company, Ohio Power Company Wheeling Power Company, AEP Appalachian Transmission Company, Inc., AEP Indiana Michigan Transmission Company, Inc., AEP Kentucky Transmission Company, Inc., AEP Ohio Transmission Company, Inc. and AEP West Virginia Transmission Company, Inc.
E-27	EL17-76-000	East Texas Electric Cooperative, Inc. v. Public Service Company of Oklahoma, Southwestern Electric Power Company, AEP Oklahoma Transmission Company and AEP Southwestern Transmission Company
E-28	EL17-59-000	Joint California Complainants v. Pacific Gas and Electric Company
E-29	EL16-120-001	New England Power Generators Association, Inc. v. ISO New England Inc.

GAS

G-1	OR14-4-000 OR14-4-001	Guttman Energy, Inc., d/b/a, Guttman Oil Company, and PBF Holding Company, LLC v. Buckeye Pipe Line Company, L.P. and Laurel Pipe Line Company, L.P.
G-2	RP17-887-000	Equitrans, L.P.

HYDRO

H-1	P-13160-010	Red River Hydro, LLC
H-2	P-2146-217	Alabama Power Company
H-3	P-1417-269	Jeffrey Lake Development, Inc.

CERTIFICATES

C-1	CP16-17-001	Millennium Pipeline Company, L.L.C.

Nathaniel J. Davis, Sr.,
Deputy Secretary.

A free webcast of this event is available through www.ferc.gov. Anyone with Internet access who desires to view this event can do so by navigating to www.ferc.gov's Calendar of Events and locating this event in the Calendar. The event will contain a link to its webcast. The Capitol Connection provides technical support for the free webcasts. It also offers access to this event via television in the DC area and via phone bridge for a fee. If you have any questions, visit www.CapitolConnection.org or contact Danelle Springer or David Reininger at 703-993-3100.

Immediately following the conclusion of the Commission Meeting, a press briefing will be held in the Commission Meeting Room. Members of the public may view this briefing in the designated overflow room. This statement is intended to notify the public that the press briefings that follow Commission meetings may now be viewed remotely at Commission headquarters, but will not be telecast through the Capitol Connection service.

November 2017
Commission Meeting Summaries

These are summaries of orders voted by the Federal Energy Regulatory Commission at its November 16, 2017 public meeting. The summaries are produced by FERC's Office of External Affairs and are intended to provide only a general synopsis of the orders. These summaries are not intended as a substitute for the Commission's official orders. To determine the specific actions and the Commission's reasoning, please consult the individual orders when they are posted to FERC's eLibrary found at www.ferc.gov.

A-3 – Press Release

FERC proposes a rule

E-1, *Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards*, Docket No. RM16-22-000. This Notice of Proposed Rulemaking addresses whether to approve proposed Reliability Standards PRC-027-1 (Coordination of Protection Systems for Performance During Faults) and PER-006-1 (Specific Training for Personnel) that would maintain the coordination of protection systems installed to detect and isolate faults on bulk electric system elements and would ensure that personnel are trained on specific topics essential to reliability to perform or support real-time operations of the bulk electric system.

FERC accepts a filing and denies proposed changes to NERC's CMEP program

E-2, *North American Electric Reliability Corp.*, Docket No. RR15-2-005. The order accepts NERC's 2016 ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP) Annual Report, and denies NERC's request for approval of two proposed changes to the CMEP: eliminating the public posting of compliance exceptions identified through self-logging, and expanding the use of compliance exceptions to include certain moderate risk non-compliance.

FERC addresses a remand

E-3, *Public Service Company of Colorado, et al.*, Docket No. ER13-75-011, *et al.* The order addresses a remand from the U.S. Court of Appeals for the Fifth Circuit regarding the Commission's orders on Order No. 1000 compliance filings submitted by public

utility transmission providers in the WestConnect transmission planning region. The order explains why the approach the Commission accepted in the compliance orders will not result in rates that are unjust and unreasonable, why the Commission expects non-public utility transmission providers in the region to be incentivized to participate in regional cost allocation, and why rates will remain just and reasonable even if a non-public utility transmission provider does not participate in regional cost allocation for a particular transmission project for which it benefits and the project is subsequently selected in the regional transmission plan for purposes of cost allocation.

FERC accepts proposed tariff revisions

E-4, *New York Independent System Operator, Inc.*, Docket No. ER17-1310-001. This order accepts the proposed tariff revisions that establish a cost allocation method for the Alternating Current Transmission Public Policy Transmission Process.

FERC accepts a settlement

E-5, *New York Independent System Operator, Inc.*, Docket No. ER15-572-000. This order accepts the offer of New York Transco, Inc. to settle the issues concerning transmission revenues that the Commission had set for hearing in an order issued April 2, 2015.

FERC accepts a compliance filing, subject to condition

E-6, *New York Independent System Operator, Inc.*, Docket No. ER16-120-001, *et al*. This order addresses NYISO's compliance filing submitted in response to the Commission's February 19, 2015 order instituting a proceeding under section 206 of the Federal Power Act that directed NYISO to submit tariff revisions governing the retention of and compensation to generating units needed for reliability (reliability must run, or RMR, generators), and also addressed requests for rehearing and clarification of the Commission's order on NYISO's first compliance filing. The order accepts NYISO's compliance filing, subject to condition, and directs a further compliance filing. In addition, the order grants, in part, and denies, in part, the requests for rehearing and clarification.

FERC accepts proposed tariff revisions

E-7, *PJM Interconnection, L.L.C.*, Docket No. ER17-2362-000. The order accepts PJM's proposed tariff revisions incorporating cost responsibility assignments for 39 transmission projects included in the recent update to the Regional Transmission Expansion Plan approved by the PJM Board of Directors.

FERC denies rehearing

E-8, *PJM Interconnection, L.L.C.*, Docket No. ER17-249-001. The order denies rehearing of the Commission's December 22, 2016 order that accepted revisions to the PJM Open Access Transmission Tariff that extended and updated the rate mechanism for recovering the administrative costs of serving as a regional transmission organization.

FERC rejects proposed formula rate revisions

E-9, *PJM Interconnection, L.L.C.*, Docket Nos. ER17-528-000 and ER17-528-001. This order rejects Baltimore Gas and Electric's proposed revisions to its formula rate to provide a mechanism, as appropriate, to refund or recover certain deferred income tax excesses and deficiencies previously recorded and ongoing.

FERC grants request for power sales to an affiliate

E-10, *FirstEnergy Solutions Corp*., Docket No. ER17-1269-000. This order grants FirstEnergy Solutions' request to make power sales to its affiliate Potomac Edison in accordance with the terms of a Full Requirements Service agreement and transaction confirmations between FirstEnergy Solutions and Potomac Edison that were selected and entered into in accordance with a competitive solicitation process conducted by Potomac Edison. The order finds that these competitive solicitation processes satisfy the Commission's concerns regarding the potential for affiliate abuse.

FERC grants request for power sales to an affiliate

E-11, *FirstEnergy Solutions Corp*., Docket No. ER17-1272-000. The order grants FirstEnergy Solutions' request to make power sales to its affiliate West Penn Power (West Penn) in accordance with the terms of two Default Service Supplier Master Agreements and transaction confirmations between FirstEnergy Solutions and West Penn that were selected and entered into in accordance with two separate competitive solicitation processes conducted by West Penn. The order finds that these competitive solicitation processes satisfy the Commission's concerns regarding the potential for affiliate abuse.

FERC accepts filings, subject to condition

E-12, *Southwest Power Pool, Inc*., Docket No. ER17-889-000. The order accepts (1) an executed Service Agreement for Network Integration Transmission Service between SPP as transmission provider and Kansas Municipal Energy Agency (KMEA) as network customer and (2) an executed Network Operating Agreement among SPP as transmission provider, KMEA as network customer, and Sunflower Electric Power Corporation as host transmission owner. The order also directs SPP to submit a compliance filing.

FERC accepts proposed tariff revisions

E-13, *Southwest Power Pool, Inc*., Docket No. ER17-1482-000. The order accepts SPP's proposed revisions to Attachment AE of the Open Access Transmission Tariff to replace the terms "Head-room" and "Floor-room" with the new term "Instantaneous Load Capacity," and to add the term "Operator input" to the list of inputs that are used in its Reliability Unit Commitment determinations.

FERC accepts a filing, subject to condition

E-14, *Entergy Arkansas, Inc*., Docket No. ER17-1160-000, *et al*. The order accepts Entergy Services, Inc.'s filing of six amended power purchase agreements, subject to the condition that Entergy make a compliance filing to clarify the date on which Entergy's Unit Power Sales and Designated Power Purchases Tariff began to apply to the amended power purchase agreements.

FERC rejects a filing, directs an additional compliance filing

E-15, *Entergy Services, Inc*., Docket No. ER10-1350-006. The order rejects Entergy's November 19, 2016 compliance filing, finding that Entergy must calculate interest compounding on the interest component of the payments at issue until the date the interest payment is actually made. The order directs Entergy to file an additional compliance filing.

FERC grants a limited waiver

E-16, *Entergy Louisiana, LLC*, Docket No. ER17-897-000. This order grants Entergy Louisiana's request that the Commission grant limited waiver of sections 35.14 and 35.19a of the Commission's regulations. Entergy Louisiana states that the waivers would allow Entergy Louisiana to credit a wholesale, cost-based requirements customer a proportional share of a supplemental judgment and partial award received by Entergy Louisiana from the United States Department of Energy (DOE) as a result of DOE's breach of a contract for disposal of spent nuclear fuel.

FERC denies requests for rehearing and clarification

E-17, *Louisiana Public Service Commission v. Entergy Corp*., Docket No. EL09-61-006. This order denies requests for rehearing and clarification of the Commission's Opinion No. 548, which determined the methodology to calculate refunds due as a result of the Commission's finding in Opinion No. 521 that Entergy had violated the Entergy System Agreement through improper allocation of energy used to source Entergy Arkansas' off-system sales of energy from 2000 through 2009.

FERC rejects proposed revisions

E-18, *NorthWestern Corporation*, Docket No. ER17-1221-000. This order rejects NorthWestern's proposed revisions to its creditworthiness procedures, without prejudice.

FERC accepts proposed formula rate revisions, subject to condition

E-19, *Midcontinent Independent System Operator, Inc*., Docket No. ER17-1014-000. The order accepts, subject to condition, MISO's proposed revisions to the Formula Rate for Otter Tail Power (Otter Tail) included in Attachment O of the MISO Open Access Transmission, Energy, and Operating Reserve Markets Tariff. The proposed revisions facilitate the inclusion of the annual transmission revenue requirements associated with Basin Electric Power Cooperative's eligible transmission facilities located within the Otter Tail pricing zone.

FERC accepts tariff revisions

E-20, *Arizona Public Service Company*, Docket Nos. ER16-938-005, *et al.* The order accepts APS' October 25, 2016 and March 31, 2017 filings proposing revisions to its Open Access Transmission Tariff to comply with the Commission's September 26, 2016 order addressing APS' participation in the Energy Imbalance Market operated by California Independent System Operator Corporation.

FERC accepts proposed tariff revisions, directs a compliance filing

E-21, *Louisville Gas and Electric Company*, Docket No. ER17-558-000. The order accepts, subject to condition, a filing submitted by Louisville Gas and Electric and Kentucky Utilities (LG&E\KU) proposing revisions to their open access transmission tariff and to their network operating agreement under the tariff. The order, among other things, clarifies that imbalance and reserve ancillary services are not intended to be used as backup supply. The order also directs LG&E\KU to submit a compliance filing.

FERC accepts an agreement

E-22, *Bishop Hill Energy LLC*, Docket No. ER17-1386-000. This order accepts a shared facilities agreement that has been conformed to account for an assignment of obligations from First Wind Energy LLC to First Wind O&M.

FERC denies a motion

E-23, *Saguaro Power Company, A Limited Partnership*, Docket Nos. EL16-78-001 and QF90-203-008. This order denies the Nevada Bureau of Consumer Protection's Motion for Refund Compliance Report, in which the Nevada Bureau sought information regarding Saguaro Power's compliance with Commission orders that granted, in part, and denied, in part, Saguaro Power's requested waiver of the cogeneration facilities' operating and efficiency standards. The order notes that, in the underlying orders, the Commission had denied a similar request for informational filings detailing Saguaro Power's compliance. The order finds no additional basis that would support ordering such informational filings now.

FERC grants waivers for Years 2016 & 2017, dismisses waiver for Year 2018

E-24, *EF Kenilworth, LLC*, Docket Nos. EL17-74-000 and QF90-73-009. This order grants waiver of the cogeneration facility operating and efficiency standards for the years 2016 and 2017, but dismisses as premature the requested waiver for 2018. The order finds that EF Kenilworth may be able to meet the Commission's operating and efficiency standards in 2018. However, the order states that, if EF Kenilworth later determines that it will be unable to meet the operating and efficiency standards for 2018, it may request waiver at that time.

FERC accepts a filing, subject to condition; grants waiver; and denies, in part, and grants, in part, requests for rehearing and clarification

E-25, *Coalition of MISO Transmission Customers v. Midcontinent Independent System Operator, Inc*., Docket Nos. EL16-112-001 and ER17-892-000. This order accepts, subject to condition, MISO's filing that was submitted in compliance with the Commission's December 6, 2016 order issued in Docket No. EL16-112-000. The December 6 order granted, in part, and denied, in part, Coalition of MISO Transmission Customers' complaint regarding MISO's calculation of the Sub-Regional Export Constraint from MISO South to MISO Midwest used in the 2016/17 Planning Resource Auction. This order grants waiver of section 64.1.4 of MISO's tariff to allow market participants additional time to compile and format required information in accordance with the new requirements proposed by MISO on compliance. This order also denies, in part, and grants, in part, requests for rehearing and clarification of the December 6 order.

FERC addresses a complaint, establishes hearing and settlement judge procedures

E-26, *American Municipal Power, Inc., et al. v. Appalachian Power Co., et al*., Docket No. EL17-13-000. The order sets for hearing and settlement judge procedures a return on equity complaint filed by American Municipal Power, Inc., *et al.*, against the AEP-East companies.

FERC addresses a complaint, establishes hearing and settlement judge procedures

E-27*, East Texas Electric Cooperative, Inc. v. Public Service Company of Oklahoma, et al.*, Docket No. EL17-76-000. The order sets for hearing and settlement judge procedures a return on equity complaint filed by East Texas Electric Cooperative, Inc. against the AEP-West companies.

FERC denies a complaint

E-28, *Joint California Complainants v. Pacific Gas and Electric Company*, Docket No. EL17-59-000. The order denies a complaint requesting additional refund protection in case PG&E's proposed rates in its eighteenth transmission owner tariff filing are reduced below PG&E's last clean rate. The order finds that complainants have failed to carry their burden under Federal Power Act section 206 to demonstrate that a rate reduction below the last clean rate may be warranted.

FERC denies request for clarification or rehearing

E-29, *New England Power Generators Association, Inc. v. ISO New England Inc.*, Docket No. EL16-120-001. The order denies NEPGA's request to clarify the Commission's January 16, 2017 order, where the Commission required ISO-NE to revise the method by which it calculated the strike price that triggers the Peak Energy Rent (PER) mechanism within ISO-NE's Forward Capacity Market. NEPGA asked the Commission to clarify the calculation of the PER Adjustment. The order finds NEPGA's proposed interpretation incorrect. The order also denies NEPGA's alternative request for rehearing.

G-1, *Guttman Energy, Inc., d/b/a Guttman Oil Company, and PBF Holding Company, LLC v. Buckeye Pipe Line Company, L.P. and Laurel Pipe Line Company, L.P.*, Docket No. OR14-4-000, *et al.* The order affirms, in part, and reverses, in part, the determinations of the Presiding Judge in the April 19, 2016 Initial Decision. This proceeding involves a complaint alleging that Buckeye has been unlawfully charging interstate rates for intrastate movements, and has significant market power in certain markets for which Buckeye has market-based rate authority. The order affirms the Presiding Judge's finding that the essential character of the movements in question is interstate and affirms, in part, and reverses, in part, the Presiding Judge's findings regarding market power.

FERC approves an optional service

G-2, *Equitrans, L.P.*, Docket No. RP17-887-000. This letter order approves an optional service, called Enhanced Firm Transportation, which is intended to improve flexibility, and is similar to optional services that the Commission has approved for other pipelines.

FERC grants a two-year stay

H-1, *Red River Hydro, LLC,* Project No. 13160-010. The order grants Red River Hydro's request for a two-year stay of the commencement and completion of construction deadlines for its Overton Lock and Dam Hydroelectric Project, to be located at the U.S. Corps of Engineers' John H. Overton Lock and Dam on the Red River in Rapides Parish, Louisiana. The order finds that Red River Hydro, for reasons beyond its control, will not be able to timely commence project construction.

FERC partially grants one rehearing request and denies a second

H-2, *Alabama Power Company,* Project No. 2146-217. This order acts on two requests for rehearing of Commission staff's February 2, 2017 order modifying and approving Alabama Power's Recreation Plan for its Coosa River Hydroelectric Project, located on the Coosa River in Cherokee, Etowah, Calhoun, St. Clair, Talladega, Shelby, Coosa, Chilton, and Elmore counties, Alabama, and Floyd County, Georgia. The order grants rehearing on one issue raised in the Coosa River Paddling Club's request for rehearing and denies all remaining issues in both rehearing requests.

FERC denies rehearing

H-3, *Jeffrey Lake Development, Inc.*, Project No. 1417-269. The order denies Jeffrey Lake Development's request for rehearing of Commission staff's July 27, 2017 letter, addressing allegations of license non-compliance with regard to Jeffrey Lake, a reservoir at one of the developments of the Kingsley Project, located on the North Platte and Platte Rivers in Garden, Keith, Lincoln, Gosper, and Dawson counties, Nebraska. The order upholds staff's rejection of Jeffrey Lake Development's allegations of non-compliance.

FERC denies requests for rehearing and for stay

C-1, *Millennium Pipeline Company, L.L.C.*, Docket No. CP16-17-001. This order denies landowners' and an area resident's requests for rehearing of the Commission's November 9, 2016 order granting a certificate of public convenience and necessity to Millennium for its Valley Lateral Project. The order finds that the project is subject to the Commission's jurisdiction and reaffirms the determinations of the November 2016 order.

Summaries of NERC Items on FERC November 16, 2017 Open Meeting Agenda

1. Agenda Item E-1, in Docket No. RM16-22-000 *Coordination of Protection Systems for Performance During Faults and Specific Training for Personnel Reliability Standards*

On September 2, 2016, the North American Electric Reliability Corporation ("NERC") filed a petition for approval of:

- proposed Reliability Standards PRC-027-1 and PER-006-1;
- proposed new and revised definitions to be incorporated into the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary") for the following terms: (i) Protection System Coordination Study; (ii) Operational Planning Analysis; and (iii) Real-time Assessment;
- the retirement of Reliability Standard PRC-001-1.1(ii);
- the associated Implementation Plans; and
- the associated Violation Risk Factors and Violation Severity Levels.

The purpose of the proposed Reliability Standards and the proposed NERC Glossary definitions is to (1) maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System ("BES") Elements, such that those Protection Systems operate in the intended sequence during Faults; and (2) require registered entities to provide training to their relevant personnel on Protection Systems and Remedial Action Schemes to help ensure that the BES is reliably operated. Protection Systems help maintain reliability by isolating faulted equipment, thereby reducing the risk of instability or Cascading, and leaving the remainder of the BPS operational and more capable of withstanding a future Contingency.

2. Agenda Item E-2, in Docket No. RR15-2-005 *Compliance Monitoring and Enforcement Program*

On February 21, 2017, NERC filed its annual informational filing to review the progress of the risk-based compliance and enforcement program, in accordance with the Federal Energy Regulatory Commission's February 19, 2015 Order on Electric Reliability Organization Reliability Assurance Initiative and Requiring Compliance Filing[1] and the November 4, 2015 Order Conditionally Accepting Compliance Filings.[2]

NERC proposed the following enhancements to the risk-based CMEP based on the Electric Reliability Organization Enterprise's experience with the implementation of these programs over

[1] *North American Electric Reliability Corp*., 150 FERC ¶ 61,108 (2015) (February 19 Order). In the February 19 Order, the Commission conditionally approved the implementation of the risk-based CMEP, finding that the "overall goal of focusing ERO and industry compliance resources on higher-risk issues that matter more to reliability is reasonable." *Id*. at P 2. The Commission also directed NERC, among other things, to submit an annual informational filing, within one year from the date of the issuance of the order; to review the progress of the risk-based CMEP; and to address a number of other specific topics regarding oversight processes and implementation assessment. Id. at PP 32, 42-43, 46, 49-52.

[2] *North American Electric Reliability Corp*., 153 FERC ¶ 61,130 (2015) (November 4 Order). The November 4 Order conditionally accepted NERC's May 20 and July 6 compliance filings.

2016: (1) providing minimal risk Compliance Exceptions identified through self-logging to FERC non-publicly; and (2) expanding the use of Compliance Exceptions to include certain moderate risk noncompliance currently processed under the Find, Fix, Track, and Report program.

Comments were due March 14, 2017. Timely interventions and comments in support of NERC's proposal were filed by PPL Electric Utilities Corporation, Edison Electric Institute, and American Electric Power System. MISO Transmission Owners filed a motion to intervene out of time and also submitted comments in support of NERC's proposal. Joint commenters American Public Power Association, the Electricity Consumers Resource Council, the National Rural Electric Cooperative Association, and the Transmission Access Policy Study Group filed comments in support of NERC's proposal to allow certain moderate risk noncompliance to be considered as Compliance Exceptions and opposed NERC's proposal to provide minimal risk Compliance Exceptions identified through self-logging to FERC non-publicly.