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 #17-2
June 7, 2017 10:00 a.m. – 5:00 p.m. EST
June 8, 2017 8:00 a.m. – 12:00 p.m. EST
Hampton Inn & Suites Saratoga Springs Downtown Hotel
25 Lake Avenue
Saratoga Springs, New York
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 April 4, 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 Approval for the Enhanced Periodic Review to NERC's Template

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	6/7/17 Call-In

Project 2013-03 Geomagnetic Disturbance Mitigation	3/17/17 (I)		Mark Olson	1:00PM
Project 2016-03 Cyber Security Supply Chain Management	6/15/17 (F)	6/15/17 (I)	Mark Olson	1:15PM
Project 2016-02 Modifications to CIP Standards	4/11/17 (I)	2/8/17 (F)	Sean Cavote Mat Bunch	1:30PM
Project 2015-10 Single Points of Failure TPL-001	5/24/17 (I)		Latrice Harkness	1:45PM
Revisions to the NERC Standard Processes Manual	5/3/17 (F)	5/3/17 (I)	Chris Larson	2:00PM
Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	2/23/17 (F)		Darrel Richardson	2:00PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)		Darrel Richardson	2:15PM
Project 2016-04 Modifications to PRC-025-1	4/3/17 (I)		Scott Barfield-McGinnis	2:30PM
Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards	4/13/17 (F)		Scott Barfield-McGinnis	2:45PM
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 Automatic Underfrequency Load Shedding PRC-006-NPCC-02 status update
  8.1.2 PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance status update

9.0 NPCC Non-Standards

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

9.1 Directories:
  9.1.1 Directory#8 *System Restoration* – (status of CO11 review).

9.1.2 Directory#9 and #10 *Real and Reactive Capability Verification* - (status of TFCO review).

9.1.3 Directory#7 *SPS* and NPCC Glossary term SPS – (status of PRC -12-2)

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

9.1.5 A-01 *Criteria for Review and Approval of Documents* – (status of TFCP review).

- RSC to consider incorporating A-01 into the Directory Review and Revision Manual

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

9.2 RAS Implementation/Transition

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	

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

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

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

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 six new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

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

13.3 Standard Committee 2017 Meeting Schedule

January 18th - Call	March 15th - WECC	April 19th – Call
June 14th – Atlanta	July 18th – Call	September 7th – MRO
October 18th – Call	December 6th - Atlanta	

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

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, Lewiston NY
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	

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 #17-1
March 8, 2017 10:00 a.m. – 5:00 p.m. EST
March 9, 2017 8:00 a.m. – 12:00 p.m. EST
FRCC: Suite 600
3000 Bayport Drive
Tampa, Florida
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 February 7, 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	
3.	Ruida Shu	Northeast Power Coordinating Council		1 & 2	
4.	Peter Heidrich	FRCC	Guest	1 & 2	
5.	Juan Villar	FERC	Guest	1	
6.	Howard Gugel	NERC	Guest	1	
7	Herb Schrayshuen	Power Advisors, LLC - Proxy for NextEra Energy, LLC	4	1 & 2	Via Phone
8.	Michael Jones	National Grid	3	1 & 2	
9.	Ron Falsetti	AESI, Inc.	Guest	1 & 2	
10.	Kelly Silver	Consolidated Edison Co. of New York, Inc.	1, 3, 4 & 5	1 & 2	
11.	David Ramkalawan	Ontario Power Generation, Inc.	4	1 & 2	
12.	Si Truc Phan	Hydro-Québec TransÉnergie	2	1 & 2	
13.	Navneet Singh	IESO	Guest	1 & 2	Via Phone
14.	Jim Grant	New York Independent System Operator	2	1 & 2	

15.	Payam Farahbakhsh	Hydro One Networks	1	1 & 2	
16.	Ben Wu	Orange & Rockland Utilities, Inc.	3	1 & 2	
17.	Quintin Lee	Eversource Energy	1	1 & 2	
18.	Brian Robinson	Utility Services, Inc.	5	1 & 2	
19.	Sean Bodkin	Dominion Resources Services	4	1 & 2	
20.	Glen Smith	Entergy Services, Inc	4	1 & 2	
21.	Michele Tondalo	The United Illuminating Company	1	1 & 2	Via Phone
22.	Vijay Puran	New York State Department of Public Service	6	1 & 2	Via Phone
23.	Dermot Smyth	Consolidated Edison Co. of New York, Inc.	3	2	Via Phone
24.	Kathleen Goodman	ISO-NE	2	1 & 2	Via Phone
25.	Josh Eason	ISO-NE	2	1	Via Phone
26.	John Pearson	ISO-NE	Guest	1	Via Phone
27.	Mark Olson	NERC	Guest	1	Via Phone
28.	Al McMeekin	NERC	Guest	1	Via Phone
29.	Laura Anderson	NERC	Guest	1	Via Phone
30.	Soo Jin Kim	NERC	Guest	1	Via Phone
31.	Scott Barfield-McGinnis	NERC	Guest	1	Via Phone
32.	Lauren Perotti	NERC	Guest	1	Via Phone
33.	Darrel Richardson	NERC	Guest	1	Via Phone

Introductions and Chair's Remarks
Peter Heidrich from FRCC provided a brief safety session and a presentation on FRCC background.

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

Agenda Items:

1.0 <u>Review of Agenda</u>
Guy Zito added section 5.7 Cost Effectiveness and 5.8 CMEP to the RSC Meeting Agenda.

2.0 RSC Meeting Minutes

Approval of Minutes—there was one minor revision to the roster of the Final Meeting Minutes of 12-8-16.
Sean Bodkin made a motion for approval.
Jim Grant seconded the motion.
The Meeting Minutes were approved as revised and documented.

3.0 Drafting Team Members and Executive Tracking Summary

3.1 NPCC Members on NERC Drafting Teams
The RSC members reviewed the roster and made modifications to the contacts of Project 2016-4 and Project 2016-EPR-02.

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

3.3 NERC Project Tracking Spreadsheet
CIP-013-1 Cyber Security-Supply Chain Risk Management is targeted to be submitted to the NERC BOT in August 2017.

4.0 Open Action Items

4.1 Open Action Items List
--Brian Hogue will send out a set of instruction on how to use two factor authentications to log into the NPCC website.

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 Standards Balloting and Commenting System Enhancements Overview
Howard Gugel from NERC discussed all the new updates from NERC SBS system. Members of the RSC provided a few suggestions on the SBS in regards to the comment submittal list.

5.3 PRC-012-2 Remedial Action Scheme NOPR
Currently there is a FERC NOPR pending industry comment.
FERC is seeking clarification that PRC -012-2 will not modify any of the system performance requirements under TPL-001-4. Specifically, under TPL-001-4 non-consequential load loss may not exceed 75MW~~S~~ for certain P1, P2 or P3 contingencies.
There are 83 Type II SPS, one of which is a load rejection SPS, rejecting over 75MW of load.
The revised definition of a Remedial Action Scheme (RAS) is effective on April 1, 2017.
Currently the Task Force on Coordination of Planning (TFCP) is coordinating a review of the RCC approved SPS list. Task Force on System Studies (TFSS) has annotated the list to indicate which SPS's on the list conform to the revised definition of a RAS, which SPS's on the list do not conform and which protection systems not previously identified as a SPS now conform to the definition of a RAS.

The TFSSTask Force on System Studies has been requested to perform a risk assessment of removing those existing SPS's on the list that do not conform to the revised definition of a RAS from the list. Subsequent to the TFSS assessment the NPCC Glossary term for SPS will be revised to reference the NERC definition of a RAS.

5.4 Distributed Energy Resource Report February 2017

Ruida Shu provided a brief summary on the Distributed Energy Resource Report and Howard Gugel provided additional details on the focus for NERC in the next a few years on DER and its impact on the grid.

5.5 DOE Proposed Rule – Grid Security Emergency

The U.S. Department of Energy is proposing to issue regulations in regards to governing the Secretary of Energy's ability to issue an emergency order following the President's declaration of a Grid Security Emergency. The proposed procedures are intended to ensure the expeditious issuance of emergency orders under the Federal Power Act.

5.6 Lack of Quorum at FERC and Potential Impact

Due to the lack of quorum at FERC, FERC has suspended their monthly open meeting until further notice.

5.7 Cost Effectiveness

Howard Gugel provided a summary on the NERC cost effectiveness pilot. The new NERC Board of TrusteesOT Chair is looking at Cost Effectiveness with renewed interest.

5.8 CMEP

Mr. Bodkin of Dominion provided an update.

NERC has proposed enhancements to portions of the CMEP. Specifically, providing Compliance Exceptions (CE) for minimal risk self –logged violations and expanding the use of CE's to include certain moderate risk non- compliance processed through FFT.

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	3/8/17 Call-In
Project 2013-03 Geomagnetic Disturbance Mitigation	1/20/17 (I)	NA	Mark Olson	1:00PM
Project 2016-03 Cyber Security Supply Chain Management	3/6/17 (F)	3/6/17 (I)	Mark Olson	1:15PM
Project 2016-02 Modifications to CIP Standards	1/25/17 (F)	2/8/17 (F)	Al McMeekin	1:30PM
Project 2015-08 Emergency Operations	1/6/17 (F)	2/2/17 (F)	Laura Anderson	2:00PM

Project 2015-10 Single Points of Failure TPL-001	DT Nominations		Soo Jin Kim	2:15PM
Project 2016-04 Modifications to PRC-025-1	10/18/16 (F)		Scott Barfield-McGinnis	2:30PM
Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards	4/13/17 (F)		Scott Barfield-McGinnis	2:45PM
Revisions to the NERC Standard Processes Manual	10/28/15 (I)		Lauren Perotti	3:00PM
Project 2015-09 Establish and Communicate System Operating Limits	8/12/16 (I)		Darrel Richardson	3:15PM
Functional Model Advisory Group	9/7/16 (I)		Darrel Richardson	3:30PM
Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards	2/23/17 (F)		Darrel Richardson	3:45PM
Comments: (I) – Informal; (F) – Formal; (N) – Nomination Period **Ballots:** (I) – Initial; (A) – Additional; (F) – Final				

Project 2013-03 Geomagnetic Disturbance Mitigation:
Mark Olson called in at 1:00PM to discuss Project 2013-03.
The SDT met last week and reviewed the comments for the SAR.
The SDT made some minor adjustments to the SAR.
One concern was consideration of the TPL standard during implementation.
The SAR is included in the next SC meeting agenda.
The goal is to do an initial posting around June 2017.
The deadline for Project 2013-03 is May 2018.

Project 2016-03 Cyber Security Supply Chain Management:
Soo Jin Kim called in at 2:59PM to discuss Project 2016-03.
There are about 750 pages of comments submitted to NERC on Project 2016-03.
Main concerns were on Requirement 3, 4 and 5.
Entities are concerned that they will have no jurisdiction to request a vendor to provide certain data in accordance with the standard.
The initial ballot failed with a very low approval percentage.
The SDT will be meeting next week at San Antonio, Texas to review the comments.
The plan is to do another posting in April 2017.

Project 2016-02 Modifications to CIP Standards:
Al McMeekin called in to discuss Project 2016-02 at 1:30PM.
CEC and Communication networks are posted for informal comments and they are due next Monday March 13, 2017.
The SDT is currently reviewing Virtualization and Transmission Owners Control Centers (TOCC).
The plan is to post Virtualization and TOCC (White Paper) next week.

Project 2015-08 Emergency Operations:
Scott Barfield called in at 3:40PM to discuss Project 2015-08 Emergency Operations.

The Project made updates to EOP-004, EOP-005, EOP-006 and EOP-008. The revised standards have all been approved by industry and the NERC Board of Trustees~~bot~~ and are ready to be filed to FERC by the end of the March 2017.

Project 2015-10 Single Points of Failure TPL-001:
Soo Jin Kim called in at 1:44PM to discuss Project 2015-10.
The SDT met last week in Arizona and has developed majority of the draft revised language.
The plan is to do an initial posting in June 2017.
There is no official deadline for this Project on the directives.

Project 2016-04 Modifications to PRC-025-1:
Scott Barfield reviewed Project 2016-04 with the RSC Members.
The SDT is currently reviewing the SAR.
The goal is to submit the completed SAR to the SC in April 2017.

Project 2016-EPR-02 Enhanced Periodic Review of Voltage and Reactive Standards:
Scott Barfield called in at 3:40 to discuss Project 2016-EPR-02.
The recommendation by the enhanced periodic review team is to revise the standard, however the standard drafting team reviewed ~~the standard and~~ did not find a need to revise ~~the standard~~it.
The SDT will review the comments submitted by the industry and based on the comments the SDT will make a final recommendation to the SC.

Revisions to the NERC Standard Processes Manual:
Lauren Perotti called in at 3:08PM to discuss the revisions to the NERC Standard Processes Manual.
There was a small team put together ~~to~~for assisting the revisions to the NERC Standard Processes Manual.
The changes are mainly focused on Section 6, Section 7 and Section 11.
Revisions to Section 6 have been on hold pending the revisions to the other sections.
The revised language in Section 6 is intended to clarify the responsibility of Standard Committee.
Revisions to Section 7 are to clarify the NERC CMEP and streamline the balloting processes.
The plan is to reduce the existing 45-day comment period to a 30-day comment period.
The changes to Section 11 are to clarify the process used for supporting reference documents linked to a reliability standards.
There are some minor updates to section 2.1 and 3.7.
The goal is to submit the changes to SC in March 2017 and it should be posted after the March 2017 SC meeting.

Project 2015-09 Establish and Communicate System Operating Limits:
Darrel Richardson called into the meeting to discuss Project 2015-09.
The SDT held a face to face meeting in February 2017.
The initial posting will involve the System Operating Limits (SOL) portion of the project. The Interconnection Reliability Operating Limits (IROL) portion of the project will start in 2018 or 2019,

A working group is doing analysis on IROL's since inconsistencies exist in how IROL's are determined.
The next meeting will be in the first week of April 2017.
The goal is to have all the initial documents ready for posting for June 2017.

Functional Model Advisory Group:
Howard Gugel provided an update on the Functional Model Advisory Group.
~~At the SOTC meeting, members agreed to eliminate all changes to the Functional Model and just focus on the definitions at this point.~~
At the SOTC meeting, members agreed to limit the changes to the NERC Functional Model Document. The changes will involve aligning terms with the NERC Glossary of Terms and the NERC Rules of Procedure. A red-line document will be prepared in April 2017 and will be posted for comment. Industry had concerns that the initial draft revision would result in registration changes. Any future changes to the NERC Functional Model will need industry consensus.
~~Any future changes to the Functional Model will need overall consensus from the industry.~~
The goal is to meet in April 2017 to update the changes to the definitions and post it again for comments.

Project 2016-EPR-01 Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards:
Darrel Richardson reviewed the Project 2016-EPR-01 with the RSC members.
It has been decided to make minor modifications to PER-003 and make a recommendation to retire PER-004.
The goal is to post the SAR in June 2017 and nominate drafting team members.

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 Automatic Underfrequency Load Shedding PRC-006-NPCC-02 status update
  8.1.2 PRC-006-3 Automatic Underfrequency Load Shedding Quebec Variance status update

9.0 NPCC Non-Standards

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

9.1 Directories:

9.1.1 Directory#8 *System Restoration* – (status of CO11 review).
Directory #8 has been posted to the Open Process for three postings. The CO-11 Working Group is currently developing draft responses to comments from the third posting on behalf of TFCO and TFCO will consider the CO-11 proposed responses at the March TFCO meeting.

9.1.2 Directory#9 and #10 *Real and Reactive Capability Verification* - (status of TFCO review).
TFCO has recommended that D#9 and D#10 can be retired in consideration of MOD-025-2 which is enforceable and subject to an Implementation Plan that concludes in 2019.

The TFCO retirement recommendation was posted to the Open Process and TFCO is currently reviewing comments received.

Subsequent to TFCO approval, the retirement recommendation will be sent to the RCC and balloted by the Full Members for final approval.

Directory#9 and #10 and the existing TOP Verification program will remain in force until MOD-25-2 is 100% enforceable in July 2019.

9.1.3 Directory#7 *SPS* and NPCC Glossary term SPS – (status of PRC -12-2)
A review of the Directory #7 criteria by the TFSP is pending the final rule on PRC -012-2. Currently FERC has issued a NOPR seeking industry comment on the proposed standard.

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

The TFCP has approved the Scope of Work for the CP-11 Working Group which will be conducting the review of the A-10.

CP-11 will be asked to develop alternative methodologies to identify critical facilities within NPCC.

CP-11 will conduct an initial meeting to develop an Action Plan for the review.

The CP-11 review will be conducted in two phases. The first phase during 2017 will identify recommended alternative methodologies for RCC consideration. The second phase in 2018 will test the alternative methodology for subsequent approval by the Full Members.

9.1.5 A-01 *Criteria for Review and Approval of Documents* – (status of TFCP review).

TFCP updated the A-01 through two Open Process postings and the revised A-01 has been approved by the RCC pending final ballot approval by the Full Members.

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

TFCO Working Groups CO-1 (D#5) and C-8 (D#2) reviewing initial reformatted drafts of each Directory.

The goal of both reviews will be to reformat the criteria into NERC style criteria requirements and to ensure consistency with evolving NERC standards.

9.2 RAS Implementation/Transition

The revised NERC definition of a RAS becomes effective on April 1, 2017.

The NPCC SPS list has been annotated by the TFSS to reflect which existing SPS's conform to the revised definition, which existing SPS's do not conform to the revised definition and which protection systems not previously on the SPS list now conform to the revised definition and which have now been added to the list.

The TFCP is coordinating the regional transition to the RAS definition.

Currently TFSS has been requested to perform a risk assessment of those SPS's on the list ~~which do~~ not conform to the revised definition. This assessment will inform the decision to revise the NPCC Glossary term for SPS to 'See NERC RAS' please refer to Agenda Item 5.3.

FERC has issued a NOPR on PRC -012-2 and pending the Final Rule TFSP will begin a review of the SPS criteria in Directory#7 to ensure the criteria is consistent with the new standard.

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
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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	

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

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

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

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 no new Lesson Learned issued since the last RSC meeting.

13.2 Alerts

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

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

13.3 Standard Committee 2017 Meeting Schedule

January 18th - Call	March 15th - WECC	April 19th – Call
June 14th – Atlanta	July 18th – Call	September 7th – MRO
October 18th – Call	December 6th - Atlanta	

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

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, Lewiston NY
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	

The meeting is adjourned at 10:47AM on March 9, 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
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
2009-02	Real-time Monitoring and Analysis Capabilities	Standard	T.J. (Tim) Kucey	PSEG Fossil, LLC		Timothy.Kucey@pseg.com
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
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
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard				
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard				
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard				
2013-03	Geomagnetic Disturbance Mitigation	Standard	Per-Anders Lof Rui Sun	National Grid Dominion	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		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the Rules of Procedure (Appendix 2 of the Rules of Procedure)	Standard	Jill Loewer	Utility Services		jill.loewer@utilitysvcs.com
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard	Connie Lowe Karen Backmen	Dominion IESO	804-819-2917	connie.lowe@dom.com Karen.backmen@ieso.ca
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	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	Standard	Tim Kucey	PSEG Fossil, LLC		
2016-EPR-02	Enhanced Periodic Review of VAR Standard					

Source = NERC Standard Drafting Team Rosters - September 2016

Projects Added:

1. Project 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009
2. Project 2015-07 Internal Communications Capabilities - COM-001
3. Project 2015-08 Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008

NPCC Representatives on NERC Standards Drafting Teams						
Project No.	**Project Title**	**DT Type**	**NPCC Representatives**	**Company**	**Telephone**	**E-mail Address**
2007-06	Phase 1: System Protection Coordination	Standard	None			
2007-06.2	Phase 2: System Protection Coordination	Standard	Ruida Shu Po Bun Ear	NPCC Hydro-Quebec TransEnergie	917-934-7976	rshu@npcc.org ear.po-bun@hydro.qc.c
2007-11	Disturbance Monitoring	Standard	Lee Pedowicz	NPCC	212-840-1070	lpedowicz@npcc.org
2007-17.4	PRC-005 FERC Order No. 803 Directive	Standard				
2008-02	Undervoltage Load Shedding	Standard	Charles-Eric Langlois	Hydro-Quebec TransEnergie	514-879-4100	langlois.charles-eric@hydro.qc.ca
2009-02	Real-time Monitoring and Analysis Capabilities	Standard	T.J. (Tim) Kucey	PSEG Fossil, LLC		Timothy.Kucey@pseg.com
2009-03	Emergency Operations	Standard	Connie Lowe	Dominion Resource Services, Inc.	804-819-2917	connie.lowe@dom.com
2010-03	Modeling Data (MOD B)	Standard				
2010-05.1	Protection Systems: Phase 1 (Misoperations)	Standard	Paul Difilippo	Hydro One Networks	647-328-7068	paul.difilippo@hydroone.com
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
2010-13.3	Phase 3 of Relay Loadability: Stable Power Swings	Standard				
2010-14.1	Balancing Authority Reliability-Based Control, Phase 1: Reserves	Standard				
2010-14.2	Balancing Authority Reliability-Based Control, Phase 2	Standard			-	
2010-14.2.2	Periodic Review of BAL Standards - BAL-004	Standard				
2012-09	IRO Five-Year Review	Standard	John Mulhern	Con Edison	212-580 6791	mulhernj@coned.com
2013-03	Geomagnetic Disturbance Mitigation	Standard	Emanuel Bernabeu	Dominion	804-432-8780	emanuel.e.bernabeu@dom.com
			Kenneth Fleischer	NextEra Energy	561-691-2456	kenneth.fleischer@fpl.com
			Luis Marti	Hydro One Networks	416-345-5317	luis.marti@hydroone.com
2013-04	Voltage and Reactive Control (VAR)	Standard	Sharma Kolluri	Entergy	504-576-4045	vkollur@entergy.com
2014-01	Standards Applicability for Dispersed Generation Resources	Standard	Brian Evans-Mongeon	Utility Services	802-241-1400	brian.evans-mongeon@utilitysvcs.com
2014-02	Critical Infrastructure Protection Standards Version 5 Revisions	Standard	Greg Goodrich	NYISO	518-356-7591	ggoodrich@nyiso.com
2014-03	Revisions to TOP/IRO Reliability Standards	Standard				
2014-04	Physical Security	Standard	Kathy Judge	National Grid	508-860-6040	kathleen.judge@nationalgrid.com
2015-02	Emergency Operations Periodic Review	Standard	Connie Lowe	Dominion	804-819-2917	connie.lowe@dom.com
2015-03	Periodic Review of System Operating Limit Standards	Standard	Dean Laforest	ISO-NE		
2015-04	Alignment of NERC Glossary of Terms and Definitions Used in the	Standard	Jill Loewer	Utility Services	802-241-1400	jill.loewer@utilitysvcs.com
2015-06	Interconnection Reliability Operations and Coordination - IRO-006-I	Standard				
2015-07	Internal Communications Capabilities - COM-001	Standard				
2015-08	Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008	Standard	Connie Lowe Karen Backman	Dominion IESO	804-819-2917	Connie.lowe@dom.com
Source = NERC Standard Drafting Team Rosters - June 2015						
Projects Added:						
1. Project 2015-06 Interconnection Reliability Operations and Coordination - IRO-006-East and IRO-009						
2. Project 2015-07 Internal Communications Capabilities - COM-001						
3. Project 2015-08 Emergency Operations - EOP-004, EOP-005, EOP-006, EOP-008						

NPCC Document Open Process Executive Tracking Summary

Revised: 5/8/2017 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	Criteria	A-01	Criteria for Review and Approval of Documents	Apr-17		NPCC Full Members approved a revised version of A-01 on April 21st, 2017.
2	Criteria	A-10	Classification of BPS Elements	Dec-09	CP-11 Review underway.	TFCP approved the A-10 Review Scope of Work. CP-11 review currently underway in accordance with the Scope of Work.
3	Criteria	A-15	Disturbance Monitoring Equipment Criteria	Aug-07	A-15 Retired October 2016.	A-15 Retired October 2016 (Directory#11 Approved).
4	Guideline	B-01	NPCC Guide for the Application of Autoreclosing to the Bulk Power System	Feb-13	TFSP Updated in January 2017	TFSP reviewing Open Process Comments.
5	Guideline	B-25	Guide to Time Synchronization Substation Equipment	Nov-08	B-25 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix A)
6	Guideline	B-26	Guide for Application of Disturbance Recording Equipement	Sep-06	B-26 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix B)
7	Guideline	B-27	Regional Critical Asset Identification Methodology	Feb-08	TFIST Retirement Recommendation.	B-27 Retired 6/01/2016.
8	Guideline	B-28	Guide for Generator Sequence of Events Monitoring	Feb-12	B-27 Retired October 2016.	Incorporated into Draft Directory#11 (Appendix C)
9	Procedure	C-01	NPCC Emergency Preparedness Conference Call Procedures - NPCC Security Conference Call Procedures	Jun-16	Revised.	TFCO Completed Update June 2016.
10	Procedure	C-15	Procedures for Solar Magnetic Disturbances Which Affect Electric Power Systems	Jun-16	Revised.	TFCO Completed Update June 2016.
11	Procedure	C-25	Procedure to Collect Power System Event Data	Sep-07		TFSS to Review and Update for Inclusion in D#11 as Appendix or Recommend Retirement.
12	Procedure	C-29	Procedures for System Modeling:Data Requirements and Facility Ratings	Mar-07	Retired. (MOD-032-1).	TFSS Approved Retirement January 2017.
13	Procedure	C-30	Procedure for Task Force on System Protection Review of Disturbances and Protection Misoperations	Dec-09	Retired.	TFSP Retired C-30 June 2016.
14	Procedure	C-33	Procedure for Analysis and Classification of Dynamic Control Systems	Apr-06		Pending TFSS review.
16	Procedure	C-35	NPCC Power System Restoration Guideline	Mar-16	Retired.	TFCO/CO11 established C-35 as a Reference Document.
16	Procedure	C-39	Procedure to Collect Major Disturbance Event Data	Dec-09	Retired	TFSP retired C-39 June 2016.
17	Procedure	C-43	NPCC Operational Review for the Integration of New facilities	Aug-08	Pending TFCO review.	TFCP to review Open Process Comments.
18	Procedure	C-45	Procedure for Analysis and Reporting of Protection System Misoperations	Jul-16	Revised.	TFSP revised C-45 July, 2016.

NPCC Directory Executive Tracking Summary

Revised: 5/8/2017 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		TFCO Working Group CO-8 reviewing reformatted draft of Directory#2.
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 to consider review of Directory#7 criteria and NPCC Glossary definition of SPS.
8	Directory #8	Criteria A-12	System Restoration	TFCO	Oct-10		Subsequent to PRC-005-2 approval TFCO has revised battery testing criteria. TFCP considering Open Process comments.
9	Directory #9	Criteria A-13	Verification of Generator Gross and Net Real Power Capability	TFCO	Dec-11		TFCO posted recommendation to retire D#9 and D#10 pending full enforcement of MOD-25-2. (July 2019). TFCO currently considering comments.
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: **5/8/2017** 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

5/8/2017

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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

SUMMARY
Updated: 4/14/2017
Tutorial Video (11 min)
Click here to report technical issues

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

HOME	DO NOT SORT (Filtering Ok)	Early/(Late)	Baseline/ Current	2017: Mar Apr May Jun Jul Aug Sep Oct Nov Dec	2018: Jan Feb Mar Apr May
L Project (Filter)	Deliverables (Filter)	Days (Filter)	(Filter)		
R 2013-03 - Geomagnetic Disturbance Mitigatio	TPL-007-2		Current		
Y 2015-09 - Establish and Communicate System	FAC-010-3, FAC-011-3, and FA	(330)	Current		
R 2015-10 - Single Points of Failure TPL-001	TPL-001		Current		
R 2016-02 - Modifications to CIP Standards	Directives, Control Center Con	(77)	Current		
R 2016-02 - Modifications to CIP Standards	V5TAG issues: Cyber Asset and	(107)	Current		
Y 2016-EPR-01 - Enhanced Periodic Review of Pe	PER-003-1 and PER-004-2		Current		
R 2016-EPR-02 - Enhanced Periodic Review of Ve	VAR-001-4.1 & VAR-002-4		Current		
R 2016-03 - Cyber Security Supply Chain Manage	New and revised Standard(s)		Current		
R 2016-04 - Modifications to PRC-025-1	PRC-025-2		Proposed		

Project Name	Status	Comments	Deliverable	Deadline	Priority in RSDP, click to see applicable Footnote	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	SAR / PR / WP	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 team anticipates confirming their project schedule by June 2017 once they know what white papers and other documents need to accompany development.	TPL-007-2	43249	High	N/A	N/A	N/A	N/A	Mark Olson	Jennifer Sterling	TPL-007-1	4/11/2017
Establish and Communicate System Operating Limits	Working to Initial Ballot	The drafting team met in Denver, CO February 15-17, 2017. The team continues to work on a baseline schedule.	FAC-010-3, FAC-011-3, and FAC-014-2	N/A	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	4/14/2017
Single Points of Failure TPL-001	Working to Initial Ballot	The TPL SDT meets the week of April 3, 2017 at NERC in Atlanta, GA to continue revising the standard. The group made it through the 754 SAMS and SPCS report and update the MOD references. The goal is to seek approval to post at the June 2017 SC meeting for a 45-day formal comment and initial ballot period by July 2017.	TPL-001	N/A	High	N/A	2 directives at P40 & P89 (Click this link for FERC Order)	N/A	N/A	Latrice Harkness	Mark Pratt	TPL-001	4/11/2017
Modifications to CIP Standards	Responding to Comment	The SDT is considering comments from the March 2017 informal posting.	Directives, Control Center Comm Nets (CIP-006)	N/A	High	N/A	2	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash Mayfield		4/11/2017
Modifications to CIP Standards	Posted	Two concurrent 29-day informal comment periods are open through 8 p.m. Eastern, Tuesday, April 11, 2017, for stakeholders to provide feedback on the Standard Drafting Team's (SDT's) approaches to addressing two issues from the Version 5 Transition Advisory Group (V5TAG): (1) 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; and, (2) the use of virtualization in the CIP environment.	V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), TO Control Centers Performing Transmission	N/A	High	N/A	N/A	N/A	N/A	Mat Bunch & Katherine Street	Ken Lanehome and Ash Mayfield	CIP Stds. - Unknown	4/11/2017
Cyber Security Supply Chain Management	Working to Additional Ballot	The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address "supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations." See Order No. 829, at P1. The SDT is working toward posting for an additional comment period and ballot. The team met in Atlanta the week of April 10	New and revised Standard(s)	43005	N/A	N/A	1	N/A	N/A	Mark Olson	Brenda Hampton and Angela Kimmey	New and revised Standard(s)	3/31/2017

Modifications to PRC-025-1	Responding to Comment	The Standards Authorization Request (SAR) is posted through April 3. The SAR drafting team (DT) anticipates completing their response to comments on a conference calls the week of April 3. From there, anticipate delivering the SAR to the Standards Committee on April 19 for acceptance and appointment of the SAR drafting team as the standard drafting team to develop the revisions to PRC-025-1.	New and revised Standard(s)	None, enhancemens 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 must consider the time for development and subsequent	Has not been prioritized.	N/A	N/A	N/A	Yes	Scott Barfield-McGinnis	Charles Yeung	PRC-025-1	4/11/2017

Project	**2013-03**
Project Name	Geomagnetic Disturbance Mitigation
Status	SAR / PR / WP
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 team anticipates confirming their project schedule by June 2017 once they know what white papers and other documents need to accompany development.
Deliverable	TPL-007-2
Deadline	May 29, 2018
Priority in RSDP, click to see applicable Footnote	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	Mark Olson
PMOS Liaison	Jennifer Sterling
Affected Standards	TPL-007-1
Last Updated	4/11/2017

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	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)	6/15/2017	7/30/2017	6/15/2017	7/30/2017			
CAB - Com/Add Ballot 2	9/11/2017	10/26/2017	9/11/2017	10/26/2017			
CAB - Com/Add Ballot 3	11/29/2017	1/13/2018	11/29/2017	1/13/2018			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/20/2018	3/2/2018	2/20/2018	3/2/2018			
PTB - Present to BOT	5/1/2018	5/3/2018	5/1/2018	5/3/2018			
Filing - Filing with Regulators	5/26/2018	5/29/2018	5/26/2018	**5/29/2018**			
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	4/27/2017	TBD

Project	**2015-09**
Project Name	Establish and Communicate System Operating Limits
Status	Working to Initial Ballot
Comments	The drafting team met in Denver, CO February 15-17, 2017. The team continues to work on a baseline schedule.
Deliverable	FAC-010-3, FAC-011-3, and FAC-014-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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	4/14/2017

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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							
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)	6/16/2017	7/31/2017	4/18/2016	6/2/2016	(424)		
CAB - Com/Add Ballot 2	9/14/2017	10/29/2017	7/18/2016	9/1/2016	(423)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							

CAB - Com/Add Ballot 5							
FB - Final Ballot	11/28/2017	12/8/2017	1/2/2017	1/12/2017	(330)		
PTB - Present to BOT	2/1/2018	2/3/2018	2/1/2017	2/3/2017	(365)		
Filing - Filing with Regulators	3/3/2018	3/8/2018	3/3/2017	3/8/2017	(365)		
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	Working to Initial Ballot
Comments	The TPL SDT meets the week of April 3, 2017 at NERC in Atlanta, GA to continue revising the standard. The group made it through the 754 SAMS and SPCS report and update the MOD references. The goal is to seek approval to post at the June 2017 SC meeting for a 45-day formal comment and initial ballot period by July 2017.
Deliverable	TPL-001
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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
Last Updated	4/11/2017

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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	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							
CP2 - Comment Period 2							
CIB - Com/Ballot 1 (Initial)	6/19/2017	8/2/2017	7/5/2017	8/18/2017	16		
CAB - Com/Add Ballot 2	10/18/2017	12/1/2017	10/18/2017	12/1/2017			

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	2/1/2018	2/3/2018	2/1/2018	2/3/2018			
Filing - Filing with Regulators	3/3/2018	3/6/2018	3/3/2018	3/6/2018			
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	TBD

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Responding to Comment
Comments	The SDT is considering comments from the March 2017 informal posting.
Deliverable	Directives, Control Center Comm Nets (CIP-006)
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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	4/11/2017

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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							
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							
CIB - Com/Ballot 1 (Initial)	6/15/2017	7/29/2017	12/2/2016	1/16/2017	(195)		
CAB - Com/Add Ballot 2	10/1/2017	11/14/2017	3/31/2017	5/15/2017	(184)		
CAB - Com/Add Ballot 3			8/15/2017	9/29/2017			
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							

FB - Final Ballot	1/2/2018	1/11/2018	10/17/2017	10/27/2017	(77)		78.55%
PTB - Present to BOT	2/1/2018	2/3/2018	11/7/2017	11/9/2017	(86)		
Filing - Filing with Regulators	3/1/2018	3/4/2018	12/28/2017	12/31/2017	(63)		
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.

Project	**2016-02**
Project Name	Modifications to CIP Standards
Status	Posted
Comments	Two concurrent 29-day informal comment periods are open through 8 p.m. Eastern, Tuesday, April 11, 2017, for stakeholders to provide feedback on the Standard Drafting Team's (SDT's) approaches to addressing two issues from the Version 5 Transition Advisory Group (V5TAG): (1) 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; and, (2) the use of virtualization in the CIP environment.
Deliverable	V5TAG issues: Cyber Asset and BES CA (BCA) definitions, Network and Externally Accessible Devices (ESP, ERC, IRA), TO Control Centers Performing Transmission Operator (TOP)
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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	Ken Lanehome and Ash Mayfield
Affected Standards	CIP Stds. - Unknown
Affected Standards	4/11/2017

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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							
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)	5/15/2017	6/29/2017	12/2/2016	1/16/2017	(164)		
CAB - Com/Add Ballot 2	8/1/2017	9/15/2017	3/31/2017	5/15/2017	(123)		
CAB - Com/Add Ballot 3	12/1/2017	1/15/2018	8/15/2017	9/29/2017	(108)		
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	2/1/2018	2/11/2018	10/17/2017	10/27/2017	(107)		
PTB - Present to BOT	5/1/2018	5/3/2018	11/7/2017	11/9/2017	(175)		
Filing - Filing with Regulators	6/1/2018	6/4/2018	12/28/2017	12/31/2017	(155)		
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.

Project	**2016-EPR-01**
Project Name	Enhanced Periodic Review of Personnel Performance, Training, and Qualifications Standards
Status	SAR / PR / WP
Comments	The team will be requesting the Standards Committee at their June meeting to accept a SAR to revise a Standard.
Deliverable	PER-003-1 and PER-004-2
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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 and PER-004-2, but PER-001-0.2 was not evaluated due to retirement on April 17, 2017.
Last Updated	4/14/2017

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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	2/10/2016	2/23/2016	2/10/2016	2/23/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	1/10/2017	2/23/2017	1/23/2017	3/8/2017	13		
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
PMOS request	12/13/2017	List only the EPR nomination period and recommendation posting dates.

Project	**2016-EPR-02**
Project Name	Enhanced Periodic Review of Voltage and Reactive Standards
Status	Posted
Comments	The VAR-001 and VAR-002 templates are posted for industry formal comment through April 13, 2017. The team will meet at ERCOT in Austin, TX to respond to comments April 24-27, 2017. The team noted the standards are sufficient to protect reliablity and although some things could be cleaned up, the recommendation is to not open the standards for revisions (i.e., yellow rating).
Deliverable	VAR-001-4.1 & VAR-002-4
Deadline	N/A
Priority in RSDP, click to see applicable Footnote	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	Scott Barfield-McGinnis
PMOS Liaison	Amy Casuscelli
Affected Standards	VAR-001-4.1 & VAR-002-4
Last Updated	4/11/2017

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	2/10/2016	2/23/2016	2/10/2016	2/23/2016			
Nominations - DT							
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	2/28/2017	4/13/2017	1/31/2017	3/17/2017	(28)	Other	
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
PMOS request	12/13/2017	List only the EPR nomination period and recommendation posting dates.
Delay - Other	2/8/2017	Team cleaned up templates via conference calls after in-person meeting adding two weeks, plus the Standards Committee's Standing Review Team asked for a minimum of two weeks to review.

Project	**2016-03**
Project Name	Cyber Security Supply Chain Management
Status	Working to Additional Ballot
Comments	The project will address directives from Federal Energy Regulatory Commission (FERC) Order No. 829 to develop a new or modified standard to address "supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations." See Order No. 829, at P1. The SDT is working toward posting for an additional comment period and ballot. The team met in Atlanta the week of April 10.
Deliverable	New and revised Standard(s)
Deadline	Wednesday, September 27, 2017
Priority in RSDP, click to see applicable Footnote	N/A
P81 Req (2013)	N/A
Number of Directives	1
No. of Guidances (see Note 2)	N/A
Directionally consistent with IERP findings (See Note 5)	N/A
Developer	Mark Olson
PMOS Liaison	Brenda Hampton and Angela Kimmey
Affected Standards	New and revised Standard(s)
Last Updated	3/31/2017

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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							
Nominations - DT	7/29/2016	8/18/2016	7/29/2016	8/18/2016			
QR - Quality Review							
SP1 - SAR/PR/WP Posting 1	10/20/2016	11/18/2016	10/20/2016	11/21/2016			
SP2 - SAR/PR/WP Posting 2							
CP1 - Comment Period 1							
CP2 - Comment Period 2							

CIB - Com/Ballot 1 (Initial)	2/24/2017	3/6/2017	1/19/2017	3/6/2017	(36)		
CAB - Com/Add Ballot 2	***4/30/2017***	***6/13/2017***	***4/12/2017***	***5/26/2017***	(18)		
CAB - Com/Add Ballot 3							
CAB - Com/Add Ballot 4							
CAB - Com/Add Ballot 5							
FB - Final Ballot	6/21/2017	6/30/2017	6/21/2017	6/30/2017			
PTB - Present to BOT	8/9/2017	8/11/2017	8/9/2017	8/11/2017			
Filing - Filing with Regulators	9/24/2017	9/27/2017	9/24/2017	**9/27/2017**			
PT - Post Approval Training							

PTS Change Control

Reason for Update	Date	Notes
Create project record	8/1/2016	Added project to PTS.
Periodic Update	8/21/2016	Added FERC deadline.
Baseline Schedule	11/30/2016	SDT determined the schedule.
Present Schedule to SC	3/15/2017	Accepted the SDT project schedule.
Removed Liaison	4/14/2017	Removed R. Kinard due to resigning from PMOS.

Project	**2016-04**	**Home**
Project Name	Modifications to PRC-025-1	
Status	Responding to Comment	
Comments	The Standards Authorization Request (SAR) is posted through April 3. The SAR drafting team (DT) anticipates completing their response to comments on a conference calls the week of April 3. From there, anticipate delivering the SAR to the Standards Committee on April 19 for acceptance and appointment of the SAR drafting team as the standard drafting team to develop the revisions to PRC-025-1.	
Deliverable	PRC-025-2	
Deadline	None, enhancemens 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 must consider the time for development and subsequent regulatory	
Priority in RSDP, click to see applicable Footnote	Has not been prioritized.	
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	4/11/2017	

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	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)							
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
SC Authorized Posting	9/14/2016	SAR and SAR SDT nominations.

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.

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 (Placeholder)
Note 10	

RSC Meeting #17-2, Agenda Item 4.0 Open Action Items

Item	Description	Owner	Due	Status
4.1	CIP-014 Feedback Loop Mechanism	Guy Zito	RSC Meeting	Ongoing
4.2	Si Truc Phan provide updates to the group on the status of GMD (Hydro Quebec Parameters)	Si Truc Phan	RSC Meeting	Ongoing
4.3	Post the RSC Scope of Work and Work Plan onto the NPCC RSC Website	Ruida Shu	RSC Meeting	Completed

DRAFT

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Weekly Standards & Compliance Bulletin

May 1–7, 2017

ACTIVE STANDARDS POSTINGS

Current and Upcoming Ballots (ballot periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Revisions to the NERC Standard Process Manual | Sections 2.1, 3.7, 6, 7, 8 and 11	Initial Ballot and Non-binding Poll	04/24/17	05/03/17
Join Ballot Pools (ballot pool windows close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
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Posted for Comment (comment periods close at 8:00 p.m. Eastern)			
Project	**Action**	**Start Date**	**End Date**
Revisions to the NERC Standard Process Manual | Sections 2.1, 3.7, 6, 7, 8 and 11	Use comment form.	03/20/17	05/03/17
NEW Project 2015-10 Single Points of Failure | TPL -001-5	Use comment form.	04/25/17	05/24/17

OTHER ACTIVE COMMENT PERIODS

Posted for Comment			
Posting	**Action**	**Start Date**	**End Date**
Comment Period Open for WECC Reliability Standards Development Procedures: NERC is posting the proposed WECC Reliability Standards Development Procedures for a 45-day procedural comment period. Regional Reliability Standards	Submit comments using the electronic form.	03/17/17	05/01/17

development procedures define a Regional Entity's process for development, revision, reaffirmation, and withdrawal of a Regional Reliability Standard.			
Request for Comments on Pseudo-Tie Coordination Reference Document: The NERC Operating Committee's Operating Reliability Subcommittee developed the Pseudo-Tie Coordination Reference Document to provide a guideline on the coordination needed for the implementation of pseudo-ties for generation and load. The NERC Operating Committee reviewed the initial draft of the document at its March 2017 meeting and approved it for a 45-day industry comment period. A draft version of the Reference Document is posted on the NERC website for industry comment.	Submit comments via email using the comment form.	04/21/17	06/05/17
Request for Comments on Dynamic Tag Exclusion Reference Document: The NERC Operating Committee's Operating Reliability Subcommittee developed the Dynamic Tag Exclusion Reference Document to provide a management guideline on the exclusion of tags with specific source and sink combinations due to the MW impact being included in different curtailable products. The NERC Operating Committee reviewed the initial draft of the document at its March 2017 meeting and approved it for a 45-day industry comment period. A draft version of the Reference Document is posted on the NERC website for industry comment.	Submit comments via email using the comment form.	04/21/17	06/05/17
NEW **Comment Period Open for Regional Reliability Standard BAL-502-RF-03:** The ReliabilityFirst Corporation has requested NERC to post Regional Reliability Standard BAL-502-RF-03 – Planning Resource Adequacy Analysis, Assessment and Documentation for industry review and comment as permitted by the NERC Rules of	Submit comments using the comment form.	04/28/17	06/12/28

Procedure. Documents and information about this project are available on the Reliability First's Standards Under Development page.			

STANDARDS NEWS

NEW NERC to Deploy Registered Ballot Body Self-Select Process

Appendix 3D Registered Ballot Body Criteria of the NERC Rules of Procedure states:

"Each participant, when initially registering to join the Registered Ballot Body (RBB), and annually thereafter, shall self-select to belong to one of the Segments…"

Therefore, NERC Standards staff will be initiating the *Annual RBB Self-Select Process* in the next few weeks.

QUICK LINKS

Register in the SBS
Original Balloting Software
Projected Standards Posting Schedule
Project Tracking Spreadsheet
Standards Related Questions – Single Portal
2016–2018 Reliability Standards Development Plan

- **May 2017** – Each Registered Ballot Body member will receive an email with a link to an electronic attestation confirming that there have been no material changes in the last 12 months that affect the entity's current Segment selection(s), thus the entity continues to meet the Segment qualifications (as outlined in the qualifications in Appendix 3D: *Registered Ballot Body Criteria* referenced above).
- **July 1, 2017** – Deadline for all RBB members to self-select their segments via electronic attestation.

Ballot body member will receive notifications via RBB emails, Standards Committee communications, Weekly Standards & Compliance Bulletins, other NERC email alerts, etc.

GENERAL COMPLIANCE AND ENFORCEMENT NEWS

There is no additional Compliance and Enforcement news to report for this week.

QUICK LINKS

Risk-Based CMEP (RAI Page)
Regional Consistency Reporting Tool
CIP V5 Transition Program
Risk-Based Registration Initiative
Reliability Standard Audit Worksheets
Enforcement & Mitigation: Enforcement Actions
Navigating Enforcement Data: Webinar & Presentation

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)
July 1, 2017	CIP-004-6 – Cyber Security – Personnel & Training (Requirements 2.3, 4.3, 4.4); CIP-006-6 – Cyber Security — Physical Security of BES Cyber Systems (Requirement 3.1); CIP-008-5 – Cyber Security — Incident Reporting and Response Planning (Requirement 2.1); CIP-009-6 – Cyber Security — Recovery Plans for BES Cyber Systems (Requirement 2.1–2.2); CIP-010-2 – Cyber Security — Configuration Change Management and Vulnerability Assessments (Requirement 3.1);
	MOD-033-1 – Steady-State and Dynamic System Model Validation;
	TPL-007-1 – Transmission System Planned Performance for Geomagnetic Disturbance Events
October 1, 2017	COM-001-3 – Communications
	IRO-002-5 – Reliability Coordination – Monitoring and Analysis
January 1, 2018	BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

	PRC-026-1 – Relay Performance During Stable Power Swings (Requirement 1);
April 1, 2018	IRO-018-1 – Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities
	TOP-010-1 – 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	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	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)

BOARD OF TRUSTEES AND FERC ACTION

NEW NERC Filings

On April 28, 2017, NERC filed with FERC an errata to the March 27, 2017 petition for approval of proposed Emergency Operations Reliability Standards.

NERC's 2017 filings to FERC are available here.

NEW NERC Board of Trustees Meeting Agenda Packages, Presentations, and Schedule of Events Posted

Agenda packages for the Board of Trustees, Compliance Committee, Member Representatives Committee, Corporate Governance and Human Resources Committee, and Standards Oversight and Technology Committee meetings on May 10–11, 2017 in St. Louis are now available. The schedule of events and policy input document are also available.

NEW Revisions to NERC Rules of Procedure Posted in Anticipation of Board Meeting

NERC is proposing revisions to currently effective Sections 600 (Personnel Certification) and 900 (Training and Education) of its Rules of Procedure (ROP) in anticipation of the Board of Trustees meeting on May 11, 2017.

The purpose of these revisions is twofold. First, NERC proposes to clarify the scope of the Personnel Certification Program, the Training and Education Program and the Continuing Education Program. Second, NERC proposes to modernize and align the language of the ROP with current practices of those programs.

The original proposed revisions were posted to the NERC website for comment on November 9, 2016. The proposed revisions to be presented to the NERC Board of Trustees reflect the feedback received by NERC during the November 9, 2016 comment period. A summary of the proposed changes is available as well as redlined changes to Sections 600 and 900 and a consideration of comments.

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

- Power System Modeling Workshop Technical Conference – June 20–21, 2017, Oak Brook, IL | Conference Registration
- 2017 Standards and Compliance Workshop – July 11–12, 2017, New Orleans, LA | In-person Workshop Registration | Webinar Workshop Registration | Hotel Registration | NEW Draft Agenda
- GridSecCon – October 17–20, 2017, St. Paul, MN | Conference Details | **Registration Information Coming Soon**

Webinars

There are no webinars currently scheduled.

Standing Committee Meetings and Conference Calls

- NEW Standards Committee Special Call – 4:00–4:30 p.m. Eastern, May 1, 2017 | Agenda Package | Register
- Board of Trustees Committees, Member Representatives Committee, and Board of Trustees Meetings – May 10–11, 2017 | St. Louis, MO | Meeting Registration and Hotel Information
- Operating Committee, Planning Committee, and Critical Infrastructure Protection Committee Meetings – June 6–7, 2017 | San Diego, CA | OC Meeting Registration | PC Meeting Registration | CIPC Registration | Hotel Registration

Standard Drafting Team Meetings

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.

- NEW Project 2016-02 – Modifications to CIP Standards Conference Call – Noon–1:00 p.m. Eastern, May 4, 2017 | Register
- NEW Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, May 5, 2017 | Register
- NEW Project 2016-02 – Modifications to CIP Standards Conference Call – Noon–1:00 p.m. Eastern, May 11, 2017 | Register
- NEW Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, May 12, 2017 | Register
- NEW Project 2016-02 – Modifications to CIP Standards Conference Call – Noon–1:00 p.m. Eastern, May 18, 2017 | Register
- NEW Project 2016-02 – Modifications to CIP Standards Conference Call – 11:00 a.m.–1:00 p.m. Eastern, May 19, 2017 | Register
- Project 2016-02 – Modifications to CIP Standards – May 23–25, 2017, Columbus, OH | Registration and Meeting Details
- NEW Project 2015-09 – System Operating Limits Standard Drafting Team – June 13–15, 2017, Folsom, CA| Registration and Meeting Details
- Project 2016-02 – Modifications to CIP Standards – June 20–22, 2017, Montreal, QC | Registration and Meeting Details

ABOUT THE WEEKLY STANDARDS & COMPLIANCE BULLETIN

This weekly bulletin compiles a list of standards and compliance 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 standards project, please register through our ERO portal. For more information about any of the compliance news listed in the bulletin, please contact Tiffany Whaley.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Template: [Insert Standard Number/Name]

Updated ~~February~~XX 201~~6~~7

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 (ANSI) 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 (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team. Consistent with Section 13 of the Standards Processes Manual (SPM)[2], the SC may use a public nomination process to appoint the stakeholder Subject Matter Expert (SME) team, or may use another method to appoint the ~~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 provide input~~complete their portion of~~ to the template below.

The purpose of the template is to collect background information, pose questions to guide a consistent and uniform 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 along with a report summarizing the results and~~containing its~~ recommendations for information and stakeholder input, as required by Section 13 of the NERC SPM.

Review Team Composition

	Standing Review Team	Plus Section 13 (SMEs):
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • SC (Also the SC chair or his/her delegate from the	The SC will appoint stakeholder SMEs for the particular standard(s) being reviewed. The SMEs will work together with the Standing Review Team to

[1] American National Standards Institute website: https://www.ansi.org/ http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[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 A regional representative will be included on the Standing Review Team. The Standing Review Team will meet with SMEs ~~and help~~ to ensure a consistent strategy and approach is conducted across all of the reviews.	conduct its review of the standard(s) and complete the template below.
CIP Standards	~~Chairs of the following NERC Standing Committees[5]:~~ ~~SC~~ ~~(Also the SC chair or his/her delegate from the SC will chair the Standing Review Team)~~In addition to the above Standing Review Team members; • CIPC Chair	The SC will appoint stakeholder SMEs 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 re-affirming 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 or poses no detrimental impact to reliability, or compliance– i.e., continue to monitor (Yellow); or
3. Recommend that the standard needs revision or retirement (Red).

If, upon conclusion of the review work and solicitation of industry comment, the team recommends a revision to, or a retirement of, the Reliability Standard, it must also submit a Standard Authorization

[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.~~

Request (SAR) outlining the proposed scope, along with ~~and~~ a technical justification for the revision or retirement.

A completed Periodic Review Template and any associated documentation should be submitted by email to [insert NERC contact for project].

Applicable Reliability Standard: standard and version
Team Members (include name and organization): 1. name, Company 2. name (Standards Developer)
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 potential SAR and to support any technical justification the team will submit to the SC upon conclusion of the review.)*

   ☐ Yes
   ☐ No

2. Is there any existing documentation that~~Have~~ stakeholders have previously requested clarity on the Reliability Standard in the form of an (outstanding, in progress, or approved) Request for Interpretation, ~~or~~ Compliance Application Notice (CAN) or other issue raised by the industry? (*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~~Has the Reliability Standard been identified by NERC Compliance to be 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~~may use Attachment 3: Independent Expert Evaluation Process, as necessary.

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 (i.e. are the requirements redundant with other requirements in other standards, strictly administrative in nature or are of little or no benefit to reliability)? *Use Attachment 2: Paragraph 81 Criteria for further details and to help make this determination.*

~~1.~~

Please summarize your application of Paragraph 81 Criteria, if any:

DoesShould any issue found regarding Paragraph 81 issues cause consideration of revision of this standard?

☐ 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 a~~n~~ Request for Interpretation, CAN or other stakeholder issue associated with it, or is frequently violated because of ambiguity? Some questions to determine if a standard requirement~~s~~ needs to be considered for revision are as follows;
   a. Does the Reliability Standard ~~have~~ contain ~~obvious~~ ambiguous language?
   b. Does the Reliability Standard have language that requires a level of performance that is not measurable?

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c. Are the requirements inconsistent with the purpose of the Reliability Standard?
d. Should the requirements continue to stand alone as is, or ~~should~~ is there opportunity to~~they be~~ consolidate~~d~~ the requirements into ~~with~~ other standards?
e. Is the Reliability Standard complete and self-contained or is another standard needed to meet the results based reliability objective?
f. Does the Reliability Standard use ~~consistent~~ terminology which is consistent with the intent of usage in other standards (e.g. a term such as "Control Center" should have the same meaning and intent across all the NERC standards)?

~~3.~~ **Please summarize your assessment regarding clarity:**

Does~~Should~~ any issue found regarding lack of Clarity cause consideration of revision of this standard?

☐ Yes

☐ No

~~**Please summarize your assessment:**~~

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4.3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be revisedrefined?

Please explain and provide consideration of the potential effect a revision of the term may have on other standards, and list those in which the term appears, also the importance to reliability of revising the term:

Does Should any issue found regarding lack of Clarity cause consideration of revision of this standard?

☐ Yes

☐ No

Please explain:

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5.4. **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 (RAI) and FERC and NERC guidelines?

Please summarize your assessment regarding Compliance Elements:

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Does Should any issue found regarding lack of Clarity cause consideration of revision of this standard?

☐ Yes

☐ No

If you answered "No," please identify which elements require revision, and why:

6.5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised forfor formatting and language consistency among requirements within the Reliability Standard, or for coordination with other Reliability Standards?

Please summarize your assessment regarding Consistency:

Does Should any issue found regarding Consistency cause consideration of revision of this standard?

☐ Yes

☐ No

~~**If you answered "Yes," please describe the changes needed to achieve formatting and language consistency**:~~

~~7.~~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?

Please summarize your assessment:

Does~~Should~~ any issue found regarding Consistency cause consideration of revision of this standard?

☐ 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:**~~

~~8. **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**:~~

Commented [GVZ1]: I would remove this question. The standards being graded r previous versions of them, have already have been approved by FERC and implemented. This is a question for new standards and in my view isn't germane to this exercise.

~~-~~**Cost Effectiveness**:

~~A~~ Are the costs to mitigate the identified risks reasonable versus the reliability benefit?

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7. Is the Reliability Standard the most cost--effective solution?

Please summarize your assessment:

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Does~~Should~~ any issue found regarding Cost--Effectiveness cause consideration of revision of this standard?

☐ Yes

☐ No

~~**Please summarize your assessment of the cost effectiveness of the standard:**~~

~~9.~~8. **Consideration of Generator and Transmission Interconnection Facilities:** Is responsibility for ~~generator~~ Generator Interconnection Facilities and Transmission Interconnection Facilities appropriately accounted for in the Reliability Standard?

☐ ~~Yes~~

☐ ~~No~~

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners (GOs) and/or Generator Operators (GOPs), is there any ambiguity about the inclusion of G~~g~~enerator 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 GOs and/or GOPs, is there a reliability-related need for treating G~~g~~enerator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, GOs that own and/or GOPs that operate relevant G~~g~~enerator Interconnection Facilities should be explicit in the Applicability section of the Reliability Standard.)

c. If the Reliability Standard is applicable to Transmission Operators (TOPs) and/or Distribution Providers (DPs), 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.)

Please summarize your assessment:

Does ~~Should~~ any issue found, as a result of this assessment, cause consideration of revision of this standard?

☐ Yes

☐ No

~~10.~~9. **Results-Based Standard (RBS):** Is the Reliability Standard drafted as a RBS?

~~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?

Please summarize your assessment:

Does ~~Should~~ any issue found, as a result of this assessment, cause consideration of revision of this standard?

~~Yes~~

~~No~~

~~c. Does the Reliability Standard follow the Ten Benchmarks of an Excellent Reliability Standard[6]?~~

Yes

No

II. Content

~~11.~~10. **Technical accuracy:** Is the content of the requirements technically correct, including identifying who does what and when?

Please summarize your assessment:

~~[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~~

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Commented [GVZ2]: I don't this this is needed. The standards under review have already been approved by the stakeholders, NERC BOT and FERC.
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Does ~~Should~~ any issue found, as a result of this assessment, cause consideration of revision of this standard?

☐ Yes

☐ No

~~**If not, please summarize your assessment**~~:

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~~12.~~11. **Functional Model:** Are the correct functional entities assigned to perform the requirements consistent with the Functional Model?

Please summarize your assessment:

Does ~~Should~~ any issue found, as a result of this assessment, cause consideration of revision of this standard?

☐ Yes

☐ No

~~**If not, please summarize your assessment**~~:

~~13.~~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?

Please summarize your assessment:

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Does ~~Should~~ any issue found, as a result of this assessment, cause consideration of revision of this standard?

☐ Yes

☐ No

~~**If so, please summarize your assessment**~~:

~~14.~~13. **Reliability Gaps:** Are the appropriate actions for which there should be accountability included, or is there a gap?

Please summarize your gap analysis assessment:

Does ~~Should~~ any issue found, as a result of this assessment, cause consideration of revision of this standard?

☐ Yes

☐ No

~~**If a gap is identified, please explain**~~:

~~15.~~14. **Technical Quality:** Does the Reliability Standard have a technical basis in engineering and operations?

Please summarize your assessment for Technical Quality:

Does ~~Should~~ any issue found, as a result of this assessment, cause consideration of revision of this standard?

☐ Yes

☐ No

~~**If not, please summarize your assessment**~~:

~~16. **Does the Reliability Standard reflect a higher solution than the lowest common denominator?**~~

~~☐ Yes~~

~~☐ No~~

~~**If not, please summarize your assessment**~~:

~~17.~~15. ~~**Related Regional Reliability Standards**~~: Is there a related regional Reliability Standard, and is it appropriate to recommend the regional Reliability Standard be retired~~, appended~~ and incorporated into the continent-wide standard as a Regional Variance~~, 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

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Commented [GVZ3]: This question did not prove to be of much value. All the approved standard are already deemed to be not of the LCD. I suggest considering removal

Commented [GVZ4]: I don't understand this as it was originally worded.

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, or 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 SC.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ RE-AFFIRM *(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 retirement 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):*~~

Commented [GVZ5]: I think it is too preliminary to do this. I would suggest deleting it and clarifying what the expectation is in the "Final Recommendation" section below.

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ RE-AFFIRM *(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 retirement of associated RSAW.) *RED*

SAR and Technical Justification *(If the Review Team recommends that the Reliability Standard be revised, a draft SAR ~~must be included~~, ~~and the~~ technical justification, and any other supporting documents must be included in the transmittal to the SC ~~included in the SAR~~)*:

Date submitted to Standards Committee:

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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

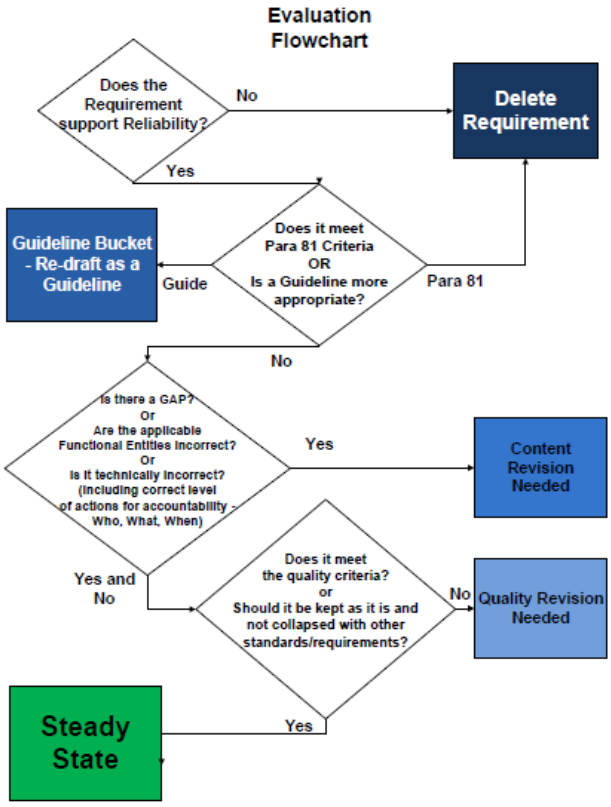


Figure 1: Evaluation Flow Chart

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, 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's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Modifications to Geomagnetic Disturbance Standards		
Date Submitted:	~~December~~ February ~~1~~23, ~~2016~~2017		
SAR Requester Information			
Name:	Frank Koza		
Organization:	PJM Interconnection / Project 2013-03 SDT Chair		
Telephone:	610-666-4228	E-mail:	frank.koza@pjm.com
SAR Type (Check as many as applicable)			
☒ New Standard		☐ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
The goal of this project is to address the Federal Energy Regulatory Commission (Commission) directives contained in Order No. 830 by modifying **TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events** and the benchmark GMD event used in GMD Vulnerability Assessments or by developing an equally efficient and effective alternative.
Industry Need (What is the industry problem this request is trying to solve?):
On September 22, 2016, the Commission issued Order No. 830 approving TPL-007-1. In the order, the Commission directed NERC to develop certain modifications to the Standard, including: • Modify the benchmark GMD event definition used for GMD Vulnerability Assessments; • Make related modifications to requirements pertaining to transformer thermal impact assessments;

SAR Information
• Require collection of GMD-related data, which ~~and for~~ NERC should~~to~~ make ~~it~~ available to the publicly ~~available~~; and • Require deadlines for Corrective Action Plans (CAPs) and GMD mitigating actions. The Commission established a deadline of 18 months from the effective date of Order No. 830 for completing the revisions, which is May 29, 2018.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The Standards Drafting Team (SDT) shall develop modifications to TPL-007-1 and the benchmark GMD event that address Commission directives from Order No. 830. The work will include development of Violation Risk Factors, Violation Severity Levels, and an Implementation Plan for the modified standards within the deadline established by the Commission in Order No. 830.
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 SDT shall address each of the Order No. 830 directives by developing modifications to requirements in TPL-007-1 and related material, or the SDT shall develop an equally efficient and effective alternative. To address concerns identified in Order No. 830, the Commission directed the following: **Benchmark GMD Event (TPL-007-1 Attachment 1 and related requirements)** • *[T]he Commission, as proposed in the NOPR, directs NERC to develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data.(P.44)* • *Without prejudging how NERC proposes to address the Commission's directive, NERC's response to this directive should satisfy the NOPR's concern that reliance on spatially-averaged data alone does not address localized peaks that could potentially affect the reliable operation of the Bulk-Power System. (P.47)* **Transformer Thermal Impact Assessment (TPL-007-1 Requirement R6)** • *Consistent with our determination above regarding the reference peak geoelectric field amplitude value, the Commission directs NERC to revise Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments. (P.65)* **Collection of GMD Data** • *The Commission … adopts the NOPR proposal in relevant part and directs NERC to develop revisions to Reliability Standard TPL-007-1 to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need. The NERC standard*

SAR Information

drafting team should address the criteria for collecting GIC monitoring and magnetometer data... and provide registered entities with sufficient guidance in terms of defining the data that must be collected.... (P.88)

- *Each responsible entity that is a transmission owner should be required to collect necessary GIC monitoring data. However, a transmission owner should be able to apply for an exemption from the GIC monitoring data collection requirement if it demonstrates that little or no value would be added to planning and operations. (P.91)*
- *NERC may also propose to incorporate the GIC monitoring and magnetometer data collection requirements in a different Reliability Standard....(P.91)*

Deadlines for Corrective Action Plans and Mitigations (TPL-007-1 Requirement R7)

- *The Commission directs NERC to modify Reliability Standard TPL-007-1 to include a deadline of one year from the completion of the GMD Vulnerability Assessments to complete the development of corrective action plans. (P.101)*
- *The Commission also directs NERC to modify Reliability Standard TPL-007-1 to include a two-year deadline after the development of the corrective action plan to complete the implementation of non-hardware mitigation and four-year deadline to complete hardware mitigation…. The Commission agrees that NERC should consider extensions of time on a case-by-case basis. (P.102)*

Reliability Functions

The Standard will Apply to the Following Functions (Check each one that applies.)

☐ Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☐ 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.

Reliability Functions		
☒	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.
☐	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.

Reliability and Market Interface Principles	
☐	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.

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

Regional Variances	
Region	Explanation
FRCC	
MRO	
NPCC	
RF	
SERC	
SPP RE	
Texas RE	
WECC	

A. Introduction

1. **Title:** Cyber Security — Electronic Security Perimeter(s)

2. **Number:** CIP-005-~~5~~6

3. **Purpose:** To manage electronic access to BES Cyber Systems by specifying a controlled Electronic Security Perimeter in support of protecting BES Cyber Systems against compromise that could lead to misoperation or instability in the BES.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1. Balancing Authority

   4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

   4.1.2.1. Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

   4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

   4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

   4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

   4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Interchange Coordinator or Interchange Authority

4.1.6. Reliability Coordinator

4.1.7. Transmission Operator

4.1.8. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each ~~Special Protection System or~~ Remedial Action Scheme where the ~~Special Protection System or~~ Remedial Action Scheme is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-005-~~5~~6:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. 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.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5 identification and categorization processes.

5. Effective Dates: See Implementation Plan for Project 2016-03

6. Background: Standard CIP-005-~~5~~ exists as part of a suite of CIP Standards related to cyber security which require the initial identification and categorization of BES Cyber Systems and require organizational, operational, and procedural controls to mitigate risk to BES Cyber Systems.~~ CIP-002-5 requires the initial identification and categorization of BES Cyber Systems. CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5, CIP-010-1, and CIP-011-1 require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems. This suite of CIP Standards is referred to as the *Version 5 CIP Cyber Security Standards.*~~

Most requirements open with, "*Each Responsible Entity shall implement one or more documented [processes, plan, ~~etc~~etc.] that include the applicable items in [Table Reference].*" The referenced table requires the applicable items in the procedures for the requirement's common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in their documented processes, but they must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

"Applicable Systems" Columns in Tables: Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the "Applicable Systems" column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5 identification and categorization processes.
- **High Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to high impact BES Cyber Systems with Dial-up Connectivity.

- **High Impact BES Cyber Systems with External Routable Connectivity** – Only applies to high impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Medium Impact BES Cyber Systems** – Applies to each BES Cyber Systems categorized as medium impact according to the CIP-002-5 identification and categorization processes.
- **Medium Impact BES Cyber Systems at Control Centers** – Only applies to medium impact BES Cyber Systems located at a Control Center.
- **Medium Impact BES Cyber Systems with Dial-up Connectivity** – Only applies to medium impact BES Cyber Systems with Dial-up Connectivity.
- **Medium Impact BES Cyber Systems with External Routable Connectivity** – Only applies to medium impact BES Cyber Systems with External Routable Connectivity. This also excludes Cyber Assets in the BES Cyber System that cannot be directly accessed through External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.
- **Electronic Access Points (EAP)** – Applies at Electronic Access Points associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

B. Requirements and Measures

R1. Each Responsible Entity shall implement one or more documented processes that collectively include each of the applicable requirement parts in *CIP-005-~~5~~ 6 Table R1 – Electronic Security Perimeter*. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].*

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-005-~~5~~ 6 Table R1 – Electronic Security Perimeter* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-~~5~~ 6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: • PCA Medium Impact BES Cyber Systems and their associated: • PCA	All applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined ESP.	An example of evidence may include, but is not limited to, a list of all ESPs with all uniquely identifiable applicable Cyber Assets connected via a routable protocol within each ESP.
1.2	High Impact BES Cyber Systems with External Routable Connectivity and their associated: • PCA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: • PCA	All External Routable Connectivity must be through an identified Electronic Access Point (EAP).	An example of evidence may include, but is not limited to, network diagrams showing all external routable communication paths and the identified EAPs.

CIP-005-~~5~~ 6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.3	Electronic Access Points for High Impact BES Cyber Systems Electronic Access Points for Medium Impact BES Cyber Systems	Require inbound and outbound access permissions, including the reason for granting access, and deny all other access by default.	An example of evidence may include, but is not limited to, a list of rules (firewall, access control lists, etc.) that demonstrate that only permitted access is allowed and that each access rule has a documented reason.
1.4	High Impact BES Cyber Systems with Dial-up Connectivity and their associated: • PCA Medium Impact BES Cyber Systems with Dial-up Connectivity and their associated: • PCA	Where technically feasible, perform authentication when establishing Dial-up Connectivity with applicable Cyber Assets.	An example of evidence may include, but is not limited to, a documented process that describes how the Responsible Entity is providing authenticated access through each dial-up connection.

CIP-005-~~5~~ 6 Table R1 – Electronic Security Perimeter			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.5	Electronic Access Points for High Impact BES Cyber Systems Electronic Access Points for Medium Impact BES Cyber Systems at Control Centers	Have one or more methods for detecting known or suspected malicious communications for both inbound and outbound communications.	An example of evidence may include, but is not limited to, documentation that malicious communications detection methods (e.g. intrusion detection system, application layer firewall, etc.) are implemented.

Rationale for Requirement R2:
Proposed Requirement R2 Parts 2.4 and 2.5 addresses Order No. 829 directives for controls on vendor-initiated remote access to BES Cyber Systems covering both user-initiated and machine-to-machine vendor remote access (P. 51). The objective is to mitigate potential risks of a compromise at a vendor during an active remote access session with a Responsible Entity from impacting the BES.

The objective of Requirement R2 Part 2.4 is for entities to have visibility of active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access) that are taking place on their system. The obligation in Part 2.4 requires entities to have a method to determine active vendor remote access sessions. While not required, a solution that identifies all active remote access sessions, regardless of whether they originate from a vendor, would meet the intent of this requirement as the objective of Part 2.4. The objective of Requirement R2 Part 2.5 is for entities to have the ability to rapidly disable active remote access sessions in the event of a system breach as specified in Order No. 829 (P. 52).

The term *vendor(s)* as used in the standard is limited to those persons, companies, or other organizations with whom the Responsible Entity, or its affiliates, contracts with to supply BES Cyber Systems and related services. It does not include other NERC registered entities providing reliability services (e.g., Balancing Authority or Reliability Coordinator services pursuant to NERC Reliability Standards). A *vendor,* as used in the standard, may include: (i) developers or manufacturers of information systems, system components, or information system services; (ii) product resellers; or (iii) system integrators.

R2. Each Responsible Entity ~~allowing Interactive Remote Access to BES Cyber Systems~~ shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in *CIP-005-~~5~~ 6 Table R2 – ~~Interactive~~ Remote Access Management*. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning and Same Day Operations].*

M2. Evidence must include the documented processes that collectively address each of the applicable requirement parts in *CIP-005-~~5~~ 6 Table R2 – ~~Interactive~~ Remote Access Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-005-~~5~~ 6 Table R2 – ~~Interactive~~ Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: • PCA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: • PCA	For all Interactive Remote Access, ~~U~~utilize an Intermediate System such that the Cyber Asset initiating Interactive Remote Access does not directly access an applicable Cyber Asset.	Examples of evidence may include, but are not limited to, network diagrams or architecture documents.
2.2	High Impact BES Cyber Systems and their associated: • PCA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: • PCA	For all Interactive Remote Access sessions, utilize encryption that terminates at an Intermediate System.	An example of evidence may include, but is not limited to, architecture documents detailing where encryption initiates and terminates.

CIP-005-~~5~~ 6 Table R2 – ~~Interactive~~ Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.3	High Impact BES Cyber Systems and their associated: • PCA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: • PCA	Require multi-factor authentication for all Interactive Remote Access sessions.	An example of evidence may include, but is not limited to, architecture documents detailing the authentication factors used. Examples of authenticators may include, but are not limited to, • Something the individual knows such as passwords or PINs. This does not include User ID; • Something the individual has such as tokens, digital certificates, or smart cards; or • Something the individual is such as fingerprints, iris scans, or other biometric characteristics.

CIP-005-~~5~~ 6 Table R2 – ~~Interactive~~ Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.4	High Impact BES Cyber Systems and their associated: • PCA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: • PCA	• Have one or more methods for determining active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access).	Examples of evidence may include, but are not limited to, documentation of the methods used to determine active vendor remote access (including Interactive Remote Access and system-to-system remote access): • Methods for accessing logged or monitoring information to determine active vendor remote access sessions; • Methods for monitoring activity (e.g. connection tables or rule hit counters in a firewall, or user activity monitoring) or open ports (e.g. netstat or related commands to display currently active ports) to determine active system to system remote access sessions; or • Methods that control vendor initiation of remote access such as vendors calling and requesting a second factor in order to initiate remote access. •

CIP-005-~~5~~ 6 Table R2 – ~~Interactive~~ Remote Access Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.5	High Impact BES Cyber Systems and their associated: • PCA Medium Impact BES Cyber Systems with External Routable Connectivity and their associated: • PCA	Have one or more method(s) to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access).	Examples of evidence may include, but are not limited to, documentation of the methods(s) used to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access), such as: • Methods to disable vendor remote access at the applicable Electronic Access Point for system-to-system remote access; or • Methods to disable vendor Interactive Remote Access at the applicable Intermediate System.

C. Compliance

1. **Compliance Monitoring Process:**

   1.1. Compliance Enforcement Authority: The Regional Entity shall serve as the Compliance Enforcement Authority ("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.

   1.2. 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 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 Responsible Entity 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:

   - Each Responsible Entity shall retain evidence of each requirement in this 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 CEA shall keep the last audit records and all requested and submitted subsequent audit records.

   1.3. Compliance Monitoring and Assessment Processes:

   - Compliance Audit
   - Self-Certification
   - Spot Checking
   - Compliance Investigation
   - Self-Reporting
   - Complaint

   1.4. Additional Compliance Information:

   None.

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-005-~~5~~ 6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	**Operations Planning and Same Day Operations**	**Medium**			The Responsible Entity did not have a method for detecting malicious communications for both inbound and outbound communications. (1.5)	The Responsible Entity did not document one or more processes for *CIP-005-~~5~~ 6 Table R1 – Electronic Security Perimeter*. (R1) OR The Responsible Entity did not have all applicable Cyber Assets connected to a network via a routable protocol within a defined Electronic Security Perimeter (ESP). (1.1) OR External Routable Connectivity through the ESP was not through an identified EAP. (1.2) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-005-~~5~~ 6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Responsible Entity did not require inbound and outbound access permissions and deny all other access by default. (1.3) OR The Responsible Entity did not perform authentication when establishing dial-up connectivity with the applicable Cyber Assets, where technically feasible. (1.4)
R2.	**Operations Planning and Same Day Operations**	**Medium**	The Responsible Entity does not have documented processes for one or more of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for one of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for two of the applicable items for Requirement Parts 2.1 through 2.3.	The Responsible Entity did not implement processes for three of the applicable items for Requirement Parts 2.1 through 2.3; ~~-~~ OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-005-~~5~~ 6)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Responsible Entity did not have one or more method(s) for determining active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access) (2.4) and one or more methods to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access) (2.5).

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a responsible entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3 Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5	11/22/13	FERC Order issued approving CIP-005-5.	

6	tbd	Modified to address certain directives in FERC Order No. 829.	Revised

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2. Furthermore,

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5's categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

CIP-005-5-6, Requirement R1 requires segmenting of BES Cyber Systems from other systems of differing trust levels by requiring controlled Electronic Access Points between the different trust zones. Electronic Security Perimeters are also used as a primary defense layer for some BES Cyber Systems that may not inherently have sufficient cyber security functionality, such as devices that lack authentication capability.

All applicable BES Cyber Systems that are connected to a network via a routable protocol must have a defined Electronic Security Perimeter (ESP). Even standalone networks that have no external connectivity to other networks must have a defined ESP. The ESP defines a zone of protection around the BES Cyber System, and it also provides clarity for entities to determine what systems or Cyber Assets are in scope and what requirements they must meet. The ESP is used in:

- Defining the scope of 'Associated Protected Cyber Assets' that must also meet certain CIP requirements.
- Defining the boundary in which all of the Cyber Assets must meet the requirements of the highest impact BES Cyber System that is in the zone (the 'high water mark').

The CIP Cyber Security Standards do not require network segmentation of BES Cyber Systems by impact classification. Many different impact classifications can be mixed within an ESP.

However, all of the Cyber Assets and BES Cyber Systems within the ESP must be protected at the level of the highest impact BES Cyber System present in the ESP (i.e., the "high water mark") where the term "Protected Cyber Assets" is used. The CIP Cyber Security Standards accomplish the "high water mark" by associating all other Cyber Assets within the ESP, even other BES Cyber Systems of lesser impact, as "Protected Cyber Assets" of the highest impact system in the ESP.

For example, if an ESP contains both a high impact BES Cyber System and a low impact BES Cyber System, each Cyber Asset of the low impact BES Cyber System is an "Associated Protected Cyber Asset" of the high impact BES Cyber System and must meet all requirements with that designation in the applicability columns of the requirement tables.

If there is routable connectivity across the ESP into any Cyber Asset, then an Electronic Access Point (EAP) must control traffic into and out of the ESP. Responsible Entities should know what traffic needs to cross an EAP and document those reasons to ensure the EAPs limit the traffic to only those known communication needs. These include, but are not limited to, communications needed for normal operations, emergency operations, support, maintenance, and troubleshooting.

The EAP should control both inbound and outbound traffic. The standard added outbound traffic control, as it is a prime indicator of compromise and a first level of defense against zero day vulnerability-based attacks. If Cyber Assets within the ESP become compromised and attempt to communicate to unknown hosts outside the ESP (usually 'command and control' hosts on the Internet, or compromised 'jump hosts' within the Responsible Entity's other networks acting as intermediaries), the EAPs should function as a first level of defense in stopping the exploit. This does not limit the Responsible Entity from controlling outbound traffic at the level of granularity that it deems appropriate, and large ranges of internal addresses may be allowed. The SDT's intent is that the Responsible Entity knows what other Cyber Assets or ranges of addresses a BES Cyber System needs to communicate with and limits the communications to that known range. For example, most BES Cyber Systems within a Responsible Entity should not have the ability to communicate through an EAP to any network address in the world, but should probably be at least limited to the address space of the Responsible Entity, and preferably to individual subnet ranges or individual hosts within the Responsible Entity's address space. The SDT's intent is not for Responsible Entities to document the inner workings of stateful firewalls, where connections initiated in one direction are allowed a return path. The intent is to know and document what systems can talk to what other systems or ranges of systems on the other side of the EAP, such that rogue connections can be detected and blocked.

This requirement applies only to communications for which access lists and 'deny by default' type requirements can be universally applied, which today are those that employ routable protocols. Direct serial, non-routable connections are not included as there is no perimeter or firewall type security that should be universally mandated across all entities and all serial communication situations. There is no firewall or perimeter capability for an RS232 cable run

between two Cyber Assets. Without a clear 'perimeter type' security control that can be applied in practically every circumstance, such a requirement would mostly generate technical feasibility exceptions ("TFEs") rather than increased security.

As for dial-up connectivity, the Standard Drafting Team's intent of this requirement is to prevent situations where only a phone number can establish direct connectivity to the BES Cyber Asset. If a dial-up modem is implemented in such a way that it simply answers the phone and connects the line to the BES Cyber Asset with no authentication of the calling party, it is a vulnerability to the BES Cyber System. The requirement calls for some form of authentication of the calling party before completing the connection to the BES Cyber System. Some examples of acceptable methods include dial-back modems, modems that must be remotely enabled or powered up, and modems that are only powered on by onsite personnel when needed along with policy that states they are disabled after use. If the dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies.

The standard adds a requirement to detect malicious communications for Control Centers. This is in response to FERC Order No. 706, Paragraphs 496-503, where ESPs are required to have two distinct security measures such that the BES Cyber Systems do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear that this is not simply redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs. Technologies meeting this requirement include Intrusion Detection or Intrusion Prevention Systems (IDS/IPS) or other forms of deep packet inspection. These technologies go beyond source/destination/port rule sets and thus provide another distinct security measure at the ESP.

Requirement R2:

See Secure Remote Access Reference Document (see remote access alert).

Rationale

During the development of this standard, references to prior versions of the CIP standards and rationale for the requirements and their parts were embedded within the standard. Upon BOT approval, that information was moved to this section.

Rationale for R1:
The Electronic Security Perimeter ("ESP") serves to control traffic at the external electronic boundary of the BES Cyber System. It provides a first layer of defense for network based attacks as it limits reconnaissance of targets, restricts and prohibits traffic to a specified rule set, and assists in containing any successful attacks.

Summary of Changes: CIP-005, Requirement R1 has taken more of a focus on the discrete Electronic Access Points, rather than the logical "perimeter."

CIP-005 (V1 through V4), Requirement R1.2 has been deleted from V5. This requirement was definitional in nature and used to bring dial-up modems using non-routable protocols into the scope of CIP-005. The non-routable protocol exclusion no longer exists as a blanket CIP-002 filter for applicability in V5, therefore there is no need for this requirement.

CIP-005 (V1 through V4), Requirement R1.1 and R1.3 were also definitional in nature and have been deleted from V5 as separate requirements but the concepts were integrated into the definitions of ESP and Electronic Access Point ("EAP").

Reference to prior version: (Part 1.1) CIP-005-4, R1

Change Rationale: (Part 1.1)
Explicitly clarifies that BES Cyber Assets connected via routable protocol must be in an Electronic Security Perimeter.

Reference to prior version: (Part 1.2) CIP-005-4, R1

Change Rationale: (Part 1.2)
Changed to refer to the defined term Electronic Access Point and BES Cyber System.

Reference to prior version: (Part 1.3) CIP-005-4, R2.1

Change Rationale: (Part 1.3)
Changed to refer to the defined term Electronic Access Point and to focus on the entity knowing and having a reason for what it allows through the EAP in both inbound and outbound directions.

Reference to prior version: (Part 1.4) CIP-005-4, R2.3

Change Rationale: (Part 1.4)
Added clarification that dial-up connectivity should perform authentication so that the BES Cyber System is not directly accessible with a phone number only.

Reference to prior version: (Part 1.5) CIP-005-4, R1

Change Rationale: (Part 1.5)
Per FERC Order No. 706, Paragraphs 496-503, ESPs need two distinct security measures such that the Cyber Assets do not lose all perimeter protection if one measure fails or is misconfigured. The Order makes clear this is not simple redundancy of firewalls, thus the SDT has decided to add the security measure of malicious traffic inspection as a requirement for these ESPs.

Rationale for R2:
Registered Entities use Interactive Remote Access to access Cyber Assets to support and maintain control systems networks. Discovery and announcement of vulnerabilities for remote access methods and technologies, that were previously thought secure and in use by a number of electric sector entities, necessitate changes to industry security control standards. Currently, no requirements are in effect for management of secure remote access to Cyber Assets to be afforded the NERC CIP protective measures. Inadequate safeguards for remote access can allow unauthorized access to the organization's network, with potentially serious consequences. Additional information is provided in ***Guidance for Secure Interactive Remote Access*** published by NERC in July 2011.

Remote access control procedures must provide adequate safeguards through robust identification, authentication and encryption techniques. Remote access to the organization's network and resources will only be permitted providing that authorized users are authenticated, data is encrypted across the network, and privileges are restricted.

The Intermediate System serves as a proxy for the remote user. Rather than allowing all the protocols the user might need to access Cyber Assets inside the Electronic Security Perimeter to traverse from the Electronic Security Perimeter to the remote computer, only the protocol required for remotely controlling the jump host is required. This allows the firewall rules to be much more restrictive than if the remote computer was allowed to connect to Cyber Assets within the Electronic Security Perimeter directly. The use of an Intermediate System also protects the Cyber Asset from vulnerabilities on the remote computer.

The use of multi-factor authentication provides an added layer of security. Passwords can be guessed, stolen, hijacked, found, or given away. They are subject to automated attacks including brute force attacks, in which possible passwords are tried until the password is found, or dictionary attacks, where words and word combinations are tested as possible passwords. But if a password or PIN must be supplied along with a one-time password supplied by a token, a fingerprint, or some other factor, the password is of no value unless the other factor(s) used for authentication are acquired along with it.

Encryption is used to protect the data that is sent between the remote computer and the Intermediate System. Data encryption is important for anyone who wants or needs secure data transfer. Encryption is needed when there is a risk of unauthorized interception of transmissions on the communications link. This is especially important when using the Internet as the communication means.

Summary of Changes: This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.

Reference to prior version: (Part 2.1) New

Change Rationale: (Part 2.1)
This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3.

Reference to prior version: (Part 2.2) CIP-007-5, R3.1

Change Rationale: (Part 2.2)
This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The purpose of this part is to protect the confidentiality and integrity of each Interactive Remote Access session.

Reference to prior version: (Part 2.3) CIP-007-5, R3.2

Change Rationale: (Part 2.3)
This is a new requirement to continue the efforts of the Urgent Action team for Project 2010-15: Expedited Revisions to CIP-005-3. The multi-factor authentication methods are also the same as those identified in the Homeland Security Presidential Directive 12 (HSPD-12), issued August 12, 2007.

A. Introduction

1. Title: Cyber Security — Configuration Change Management and Vulnerability Assessments

2. Number: CIP-0~~10-2~~10-3

3. Purpose: To prevent and detect unauthorized changes to BES Cyber Systems by specifying configuration change management and vulnerability assessment requirements in support of protecting BES Cyber Systems from compromise that could lead to misoperation or instability in the Bulk Electric System (BES).

4. Applicability:

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1 Balancing Authority

4.1.2 Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1 Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

4.1.2.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2 Each ~~Special Protection System (SPS) or~~ Remedial Action Scheme (RAS) where the ~~SPS or~~ RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3 Generator Operator

4.1.4 Generator Owner

4.1.5 Interchange Coordinator or Interchange Authority

4.1.6 Reliability Coordinator

4.1.7 Transmission Operator

4.1.8 Transmission Owner

4.2. **Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1 **Distribution Provider**: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1 Each UFLS or UVLS System that:

4.2.1.1.1 is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2 performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2 Each ~~SPS or~~ RAS where the ~~SPS or~~ RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3 Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4 Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2 **Responsible Entities listed in 4.1 other than Distribution Providers**:

All BES Facilities.

4.2.3 **Exemptions:** The following are exempt from Standard CIP-0~~10-2~~10-3:

4.2.3.1 Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2 Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3 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.

4.2.3.4 For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5 Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002-5.1 identification and categorization processes.

5. Effective Dates:

See Implementation Plan for ~~CIP-010-2~~Project 2016-03.

6. Background:

Standard CIP-010 exists as part of a suite of CIP Standards related to cyber security, which require the initial identification and categorization of BES Cyber Systems and require a minimum level of organizational, operational and procedural controls to mitigate risk to BES Cyber Systems.

Most requirements open with, "*Each Responsible Entity shall implement one or more documented [processes, plan, etc.] that include the applicable items in [Table Reference].*" The referenced table requires the applicable items in the procedures for the requirement's common subject matter.

The term *documented processes* refers to a set of required instructions specific to the Responsible Entity and to achieve a specific outcome. This term does not imply any particular naming or approval structure beyond what is stated in the requirements. An entity should include as much as it believes necessary in its documented processes, but it must address the applicable requirements in the table.

The terms *program* and *plan* are sometimes used in place of *documented processes* where it makes sense and is commonly understood. For example, documented processes describing a response are typically referred to as *plans* (i.e., incident response plans and recovery plans). Likewise, a security plan can describe an approach involving multiple procedures to address a broad subject matter.

Similarly, the term *program* may refer to the organization's overall implementation of its policies, plans, and procedures involving a subject matter. Examples in the standards include the personnel risk assessment program and the personnel training program. The full implementation of the CIP Cyber Security Standards could also be referred to as a program. However, the terms *program* and *plan* do not imply any additional requirements beyond what is stated in the standards.

Responsible Entities can implement common controls that meet requirements for multiple high and medium impact BES Cyber Systems. For example, a single training program could meet the requirements for training personnel across multiple BES Cyber Systems.

Measures for the initial requirement are simply the documented processes themselves. Measures in the table rows provide examples of evidence to show

documentation and implementation of applicable items in the documented processes. These measures serve to provide guidance to entities in acceptable records of compliance and should not be viewed as an all-inclusive list.

Throughout the standards, unless otherwise stated, bulleted items in the requirements and measures are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the BES. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

"Applicable Systems" Columns in Tables:

Each table has an "Applicable Systems" column to further define the scope of systems to which a specific requirement row applies. The CSO706 SDT adapted this concept from the National Institute of Standards and Technology ("NIST") Risk Management Framework as a way of applying requirements more appropriately based on impact and connectivity characteristics. The following conventions are used in the applicability column as described.

- **High Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as high impact according to the CIP-002-5.1 identification and categorization processes.
- **Medium Impact BES Cyber Systems** – Applies to BES Cyber Systems categorized as medium impact according to the CIP-002-5.1 identification and categorization processes.
- **Electronic Access Control or Monitoring Systems (EACMS)** – Applies to each Electronic Access Control or Monitoring System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System. Examples may include, but are not limited to, firewalls, authentication servers, and log monitoring and alerting systems.
- **Physical Access Control Systems (PACS)** – Applies to each Physical Access Control System associated with a referenced high impact BES Cyber System or medium impact BES Cyber System with External Routable Connectivity.
- **Protected Cyber Assets (PCA)** – Applies to each Protected Cyber Asset associated with a referenced high impact BES Cyber System or medium impact BES Cyber System.

B. Requirements and Measures

Rationale for Requirement R1:
Proposed requirement R1 Part 1.6 addresses directives in Order No. 829 for verifying software integrity and authenticity prior to installation in BES Cyber Systems (P. 48).

The objective of verifying software integrity and authenticity is to ensure that the software being installed in the BES Cyber System was not modified without the awareness of the software supplier and is not counterfeit.

R1. Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-0~~10-2~~10-3 Table R1 – Configuration Change Management*. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*

M1. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-0~~10-2~~10-3 Table R1 – Configuration Change Management* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-0~~10-2~~10-3 Table R1 – Configuration Change Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.1	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA Medium Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA	Develop a baseline configuration, individually or by group, which shall include the following items: 1.1.1. Operating system(s) (including version) or firmware where no independent operating system exists; 1.1.2. Any commercially available or open-source application software (including version) intentionally installed; 1.1.3. Any custom software installed; 1.1.4. Any logical network accessible ports; and 1.1.5. Any security patches applied.	Examples of evidence may include, but are not limited to: • A spreadsheet identifying the required items of the baseline configuration for each Cyber Asset, individually or by group; or • A record in an asset management system that identifies the required items of the baseline configuration for each Cyber Asset, individually or by group.

CIP-0~~10-2~~10-3 Table R1 – Configuration Change Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.2	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA Medium Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA	Authorize and document changes that deviate from the existing baseline configuration.	Examples of evidence may include, but are not limited to: • A change request record and associated electronic authorization (performed by the individual or group with the authority to authorize the change) in a change management system for each change; or • Documentation that the change was performed in accordance with the requirement.

CIP-0~~10-2~~10-3 Table R1 – Configuration Change Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.3	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA Medium Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA	For a change that deviates from the existing baseline configuration, update the baseline configuration as necessary within 30 calendar days of completing the change.	An example of evidence may include, but is not limited to, updated baseline documentation with a date that is within 30 calendar days of the date of the completion of the change.
1.4	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA Medium Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA	For a change that deviates from the existing baseline configuration: 1.4.1. Prior to the change, determine required cyber security controls in CIP-005 and CIP-007 that could be impacted by the change; 1.4.2. Following the change, verify that required cyber security controls determined in 1.4.1 are not adversely affected; and 1.4.3. Document the results of the verification.	An example of evidence may include, but is not limited to, a list of cyber security controls verified or tested along with the dated test results.

CIP-0~~10-2~~10-3 Table R1 – Configuration Change Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.5	High Impact BES Cyber Systems	Where technically feasible, for each change that deviates from the existing baseline configuration: 1.5.1. Prior to implementing any change in the production environment, test the changes in a test environment or test the changes in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration to ensure that required cyber security controls in CIP-005 and CIP-007 are not adversely affected; and 1.5.2. Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.	An example of evidence may include, but is not limited to, a list of cyber security controls tested along with successful test results and a list of differences between the production and test environments with descriptions of how any differences were accounted for, including of the date of the test.

CIP-0~~10-2~~10-3 Table R1 – Configuration Change Management			
Part	**Applicable Systems**	**Requirements**	**Measures**
1.6	High Impact BES Cyber Systems Medium Impact BES Cyber Systems Note: Implementation does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the following issues are beyond the scope of Part 1.6: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.	For a change that deviates from the existing baseline configuration associated with baseline items in Parts 1.1.1, 1.1.2, and 1.1.5, and when the method to do so is available to the Responsible Entity from the software source: 1.6.1. Verify the identity of the software source; and 1.6.2. Verify the integrity of the software obtained from the software source.	An example of evidence may include, but is not limited to a change request record that demonstrates the verification of identity of the software source and integrity of the software was performed during the baseline change.

R2. Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-0~~10-2~~10-3 Table R2 – Configuration Monitoring. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*

M2. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-0~~10-2~~10-3 Table R2 – Configuration Monitoring* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-0~~10-2~~10-3 Table R2 – Configuration Monitoring			
Part	**Applicable Systems**	**Requirements**	**Measures**
2.1	High Impact BES Cyber Systems and their associated: 1. EACMS; and 2. PCA	Monitor at least once every 35 calendar days for changes to the baseline configuration (as described in Requirement R1, Part 1.1). Document and investigate detected unauthorized changes.	An example of evidence may include, but is not limited to, logs from a system that is monitoring the configuration along with records of investigation for any unauthorized changes that were detected.

R3. Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-0~~10-2~~10-3 Table R3– Vulnerability Assessments*. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning and Operations Planning]*

M3. Evidence must include each of the applicable documented processes that collectively include each of the applicable requirement parts in *CIP-0~~10-2~~10-3 Table R3 – Vulnerability Assessments* and additional evidence to demonstrate implementation as described in the Measures column of the table.

CIP-0~~10-2~~10-3 Table R3 – Vulnerability Assessments			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.1	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA Medium Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA	At least once every 15 calendar months, conduct a paper or active vulnerability assessment.	Examples of evidence may include, but are not limited to: • A document listing the date of the assessment (performed at least once every 15 calendar months), the controls assessed for each BES Cyber System along with the method of assessment; or • A document listing the date of the assessment and the output of any tools used to perform the assessment.

CIP-0~~10-2~~10-3 Table R3 – Vulnerability Assessments			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.2	High Impact BES Cyber Systems	Where technically feasible, at least once every 36 calendar months: 3.2.1 Perform an active vulnerability assessment in a test environment, or perform an active vulnerability assessment in a production environment where the test is performed in a manner that minimizes adverse effects, that models the baseline configuration of the BES Cyber System in a production environment; and 3.2.2 Document the results of the testing and, if a test environment was used, the differences between the test environment and the production environment, including a description of the measures used to account for any differences in operation between the test and production environments.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed at least once every 36 calendar months), the output of the tools used to perform the assessment, and a list of differences between the production and test environments with descriptions of how any differences were accounted for in conducting the assessment.

CIP-0~~10-2~~10-3 Table R3 – Vulnerability Assessments			
Part	**Applicable Systems**	**Requirements**	**Measures**
3.3	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PCA	Prior to adding a new applicable Cyber Asset to a production environment, perform an active vulnerability assessment of the new Cyber Asset, except for CIP Exceptional Circumstances and like replacements of the same type of Cyber Asset with a baseline configuration that models an existing baseline configuration of the previous or other existing Cyber Asset.	An example of evidence may include, but is not limited to, a document listing the date of the assessment (performed prior to the commissioning of the new Cyber Asset) and the output of any tools used to perform the assessment.
3.4	High Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA Medium Impact BES Cyber Systems and their associated: 1. EACMS; 2. PACS; and 3. PCA	Document the results of the assessments conducted according to Parts 3.1, 3.2, and 3.3 and the action plan to remediate or mitigate vulnerabilities identified in the assessments including the planned date of completing the action plan and the execution status of any remediation or mitigation action items.	An example of evidence may include, but is not limited to, a document listing the results or the review or assessment, a list of action items, documented proposed dates of completion for the action plan, and records of the status of the action items (such as minutes of a status meeting, updates in a work order system, or a spreadsheet tracking the action items).

R4. Each Responsible Entity, for its high impact and medium impact BES Cyber Systems and associated Protected Cyber Assets, shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) for Transient Cyber Assets and Removable Media that include the sections in Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning and Operations Planning]*

M4. Evidence shall include each of the documented plan(s) for Transient Cyber Assets and Removable Media that collectively include each of the applicable sections in Attachment 1 and additional evidence to demonstrate implementation of plan(s) for Transient Cyber Assets and Removable Media. Additional examples of evidence per section are located in Attachment 2. If a Responsible Entity does not use Transient Cyber Asset(s) or Removable Media, examples of evidence include, but are not limited to, a statement, policy, or other document that states the Responsible Entity does not use Transient Cyber Asset(s) or Removable Media.

C. Compliance

1. Compliance Monitoring Process:

1.1. Compliance Enforcement Authority:

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. 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 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 Responsible Entity 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:

- Each Responsible Entity shall retain evidence of each requirement in this 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 CEA 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 Violation Investigations

Self-Reporting

Complaints

1.4. Additional Compliance Information:

None

2. Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**Medium**	The Responsible Entity has documented and implemented a configuration change management process(es) that includes only four of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)	The Responsible Entity has documented and implemented a configuration change management process(es) that includes only three of the required baseline items listed in 1.1.1 through 1.1.5. (1.1)	The Responsible Entity has documented and implemented a configuration change management process(es) that includes only two of the required baseline items listed in 1.1.1 through 1.1.5. (1.1) OR The Responsible Entity has a process to verify the identity of the software source (1.6.1) but does not have a process to verify the integrity of the software provided by the software	The Responsible Entity has not documented or implemented any configuration change management process(es). (R1) OR The Responsible Entity has documented and implemented a configuration change management process(es) that includes only one of the required baseline items listed in 1.1.1 through 1.1.5. (1.1) OR The Responsible Entity does not have a process(es) that

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					source when the method to do so is available to the Responsible Entity from the software source (1.6.2)	requires authorization and documentation of changes that deviate from the existing baseline configuration. (1.2) OR The Responsible Entity does not have a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration.(1.3) OR The Responsible Entity does not have a process(es) to determine required security controls in CIP-005 and CIP-007

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						that could be impacted by a change(s) that deviates from the existing baseline configuration. (1.4.1) OR The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration but did not verify and document that the required controls were not adversely affected following the change. (1.4.2 & 1.4.3)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						OR The Responsible Entity does not have a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration. (1.5.1) OR The Responsible Entity does not have a process to document the test results and, if using a test environment, document the differences between the test and production environments. (1.5.2) OR

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Responsible Entity does not have a process to verify the identity of the software source and the integrity of the software provided by the software source when the method to do so is available to the Responsible Entity from the software source (1.6)
R2	**Operations Planning**	**Medium**	N/A	N/A	N/A	The Responsible Entity has not documented or implemented a process(es) to monitor for, investigate, and document detected unauthorized changes to the baseline at least once every 35 calendar days~~.~~ (2.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	**Long-term Planning and Operations Planning**	**Medium**	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 15 months, but less than 18 months, since the last assessment on one of its applicable BES Cyber Systems. (3.1) OR The Responsible Entity has implemented one or more documented active vulnerability assessment processes for	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 18 months, but less than 21, months since the last assessment on one of its applicable BES Cyber Systems. (3.1) OR The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable	The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 21 months, but less than 24 months, since the last assessment on one of its applicable BES Cyber Systems. (3.1) OR The Responsible Entity has implemented one or more documented active vulnerability assessment processes for	The Responsible Entity has not implemented any vulnerability assessment processes for one of its applicable BES Cyber Systems. (R3) OR The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has performed a vulnerability assessment more than 24 months since the last assessment on one of its applicable BES Cyber Systems. (3.1)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Applicable Systems, but has performed an active vulnerability assessment more than 36 months, but less than 39 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)	Systems, but has performed an active vulnerability assessment more than 39 months, but less than 42 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)	Applicable Systems, but has performed an active vulnerability assessment more than 42 months, but less than 45 months, since the last active assessment on one of its applicable BES Cyber Systems. (3.2)	OR The Responsible Entity has implemented one or more documented active vulnerability assessment processes for Applicable Systems, but has performed an active vulnerability assessment more than 45 months since the last active assessment on one of its applicable BES Cyber Systems.(3.2) OR The Responsible Entity has implemented and documented one or more vulnerability assessment processes for each of its applicable BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Systems, but did not perform the active vulnerability assessment in a manner that models an existing baseline configuration of its applicable BES Cyber Systems. (3.3) OR The Responsible Entity has implemented one or more documented vulnerability assessment processes for each of its applicable BES Cyber Systems, but has not documented the results of the vulnerability assessments, the action plans to remediate or mitigate vulnerabilities identified in the

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-2 10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						assessments, the planned date of completion of the action plan, and the execution status of the mitigation plans. (3.4)
R4	**Long-term Planning and Operations Planning**	**Medium**	The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to manage its Transient Cyber Asset(s) according to CIP-010-2 10-3, Requirement R4, Attachment 1, Section 1.1. (R4) OR The Responsible Entity documented its plan(s) for Transient Cyber	The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to implement the Removable Media sections according to CIP-010-2 10-3, Requirement R4, Attachment 1, Section 3. (R4) OR The Responsible Entity documented its plan(s) for Transient Cyber	The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to authorize its Transient Cyber Asset(s) according to CIP-010-2 10-3, Requirement R4, Attachment 1, Section 1.2. (R4) OR The Responsible Entity documented its plan(s) for Transient Cyber	The Responsible Entity failed to document or implement one or more plan(s) for Transient Cyber Assets and Removable Media according to CIP-010-2 10-3, Requirement R4. (R4)

R #	Time Horizon	VRF	Violation Severity Levels (CIP-010-~~2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Assets and Removable Media, but failed to document the Removable Media sections according to CIP-010-~~2~~10-3, Requirement R4, Attachment 1, Section 3. (R4) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media, but failed to document authorization for Transient Cyber Assets managed by the Responsible Entity according to CIP-010-~~2~~10-3, Requirement R4,	Assets and Removable Media plan, but failed to document mitigation of software vulnerabilities, mitigation for the introduction of malicious code, or mitigation of the risk of unauthorized use for Transient Cyber Assets managed by the Responsible Entity according to CIP-010-~~2~~10-3, Requirement R4, Attachment 1, Sections 1.3, 1.4, and 1.5. (R4) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and Removable Media,	Assets and Removable Media, but failed to implement mitigation of software vulnerabilities, mitigation for the introduction of malicious code, or mitigation of the risk of unauthorized use for Transient Cyber Assets managed by the Responsible Entity according to CIP-010-~~2~~10-3, Requirement R4, Attachment 1, Sections 1.3, 1.4, and 1.5. (R4) OR The Responsible Entity documented its plan(s) for Transient Cyber Assets and	

R #	Time Horizon	VRF	Violation Severity Levels (CIP-0~~10-2~~10-3)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Attachment 1, Section 1.2. (R4)	but failed to document mitigation of software vulnerabilities or mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to CIP-0~~10-2~~10-3, Requirement R4, Attachment 1, Sections 2.1, 2.2, and 2.3. (R4)	Removable Media, but failed to implement mitigation of software vulnerabilities or mitigation for the introduction of malicious code for Transient Cyber Assets managed by a party other than the Responsible Entity according to CIP-0~~10-2~~10-3, Requirement R4, Attachment 1, Sections 2.1, 2.2, and 2.3. (R4)	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

Guideline and Technical Basis (attached).

Version History

Version	Date	Action	Change Tracking
1	11/26/12	Adopted by the NERC Board of Trustees.	Developed to define the configuration change management and vulnerability assessment requirements in coordination with other CIP standards and to address the balance of the FERC directives in its Order 706.
1	11/22/13	FERC Order issued approving CIP-010-1. (Order becomes effective on 2/3/14.)	
2	11/13/14	Adopted by the NERC Board of Trustees.	Addressed two FERC directives from Order No. 791 related to identify, assess, and correct language and communication networks.
2	2/12/15	Adopted by the NERC Board of Trustees.	Replaces the version adopted by the Board on 11/13/2014. Revised version addresses remaining directives from Order No. 791 related to transient devices and low impact BES Cyber Systems.
2	1/21/16	FERC Order issued approving CIP-010-2. Docket No. RM15-14-000	

3	tbd	Modified to address certain directives in FERC Order No. 829.	Revised

CIP-0~~10-2~~10-3 - Attachment 1

Required Sections for Plans for Transient Cyber Assets and Removable Media

Responsible Entities shall include each of the sections provided below in their plan(s) for Transient Cyber Assets and Removable Media as required under Requirement R4.

Section 1. Transient Cyber Asset(s) Managed by the Responsible Entity.

1.1. Transient Cyber Asset Management: Responsible Entities shall manage Transient Cyber Asset(s), individually or by group: (1) in an ongoing manner to ensure compliance with applicable requirements at all times, (2) in an on-demand manner applying the applicable requirements before connection to a BES Cyber System, or (3) a combination of both (1) and (2) above.

1.2. Transient Cyber Asset Authorization: For each individual or group of Transient Cyber Asset(s), each Responsible Entity shall authorize:

1.2.1. Users, either individually or by group or role;

1.2.2. Locations, either individually or by group; and

1.2.3. Uses, which shall be limited to what is necessary to perform business functions.

1.3. Software Vulnerability Mitigation: Use one or a combination of the following methods to achieve the objective of mitigating the risk of vulnerabilities posed by unpatched software on the Transient Cyber Asset (per Transient Cyber Asset capability):

- Security patching, including manual or managed updates;
- Live operating system and software executable only from read-only media;
- System hardening; or
- Other method(s) to mitigate software vulnerabilities.

1.4. Introduction of Malicious Code Mitigation: Use one or a combination of the following methods to achieve the objective of mitigating the introduction of malicious code (per Transient Cyber Asset capability):

- Antivirus software, including manual or managed updates of signatures or patterns;
- Application whitelisting; or
- Other method(s) to mitigate the introduction of malicious code.

1.5. Unauthorized Use Mitigation: Use one or a combination of the following methods to achieve the objective of mitigating the risk of unauthorized use of Transient Cyber Asset(s):

- Restrict physical access;
- Full-disk encryption with authentication;
- Multi-factor authentication; or
- Other method(s) to mitigate the risk of unauthorized use.

Section 2. Transient Cyber Asset(s) Managed by a Party Other than the Responsible Entity.

2.1 Software Vulnerabilities Mitigation: Use one or a combination of the following methods to achieve the objective of mitigating the risk of vulnerabilities posed by unpatched software on the Transient Cyber Asset (per Transient Cyber Asset capability):

- Review of installed security patch(es);
- Review of security patching process used by the party;
- Review of other vulnerability mitigation performed by the party; or
- Other method(s) to mitigate software vulnerabilities.

2.2 Introduction of malicious code mitigation: Use one or a combination of the following methods to achieve the objective of mitigating malicious code (per Transient Cyber Asset capability):

- Review of antivirus update level;
- Review of antivirus update process used by the party;
- Review of application whitelisting used by the party;
- Review use of live operating system and software executable only from read-only media;
- Review of system hardening used by the party; or
- Other method(s) to mitigate malicious code.

2.3 For any method used to mitigate software vulnerabilities or malicious code as specified in 2.1 and 2.2, Responsible Entities shall determine whether any additional mitigation actions are necessary and implement such actions prior to connecting the Transient Cyber Asset.

Section 3. Removable Media

3.1. Removable Media Authorization: For each individual or group of Removable Media, each Responsible Entity shall authorize:

3.1.1. Users, either individually or by group or role; and

3.1.2. Locations, either individually or by group.

3.2. Malicious Code Mitigation: To achieve the objective of mitigating the threat of introducing malicious code to high impact or medium impact BES Cyber Systems and their associated Protected Cyber Assets, each Responsible Entity shall:

3.2.1. Use method(s) to detect malicious code on Removable Media using a Cyber Asset other than a BES Cyber System or Protected Cyber Assets; and

3.2.2. Mitigate the threat of detected malicious code on Removable Media prior to connecting the Removable Media to a high impact or medium impact BES Cyber System or associated Protected Cyber Assets.

CIP-0~~10-2~~10-3 - Attachment 2

Examples of Evidence for Plans for Transient Cyber Assets and Removable Media

Section 1.1: Examples of evidence for Section 1.1 may include, but are not limited to, the method(s) of management for the Transient Cyber Asset(s). This can be included as part of the Transient Cyber Asset plan(s), part of the documentation related to authorization of Transient Cyber Asset(s) managed by the Responsible Entity or part of a security policy.

Section 1.2: Examples of evidence for Section 1.2 may include, but are not limited to, documentation from asset management systems, human resource management systems, or forms or spreadsheets that show authorization of Transient Cyber Asset(s) managed by the Responsible Entity. Alternatively, this can be documented in the overarching plan document.

Section 1.3: Examples of evidence for Section 1.3 may include, but are not limited to, documentation of the method(s) used to mitigate software vulnerabilities posed by unpatched software such as security patch management implementation, the use of live operating systems from read-only media, system hardening practices or other method(s) to mitigate the software vulnerability posed by unpatched software. Evidence can be from change management systems, automated patch management solutions, procedures or processes associated with using live operating systems, or procedures or processes associated with system hardening practices. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the risk from unpatched software, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Section 1.4: Examples of evidence for Section 1.4 may include, but are not limited to, documentation of the method(s) used to mitigate the introduction of malicious code such as antivirus software and processes for managing signature or pattern updates, application whitelisting practices, processes to restrict communication, or other method(s) to mitigate the introduction of malicious code. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the vendor or Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Section 1.5: Examples of evidence for Section 1.5 may include, but are not limited to, documentation through policies or procedures of the method(s) to restrict physical access; method(s) of the full-disk encryption solution along with the authentication protocol; method(s) of the multi-factor authentication solution; or documentation of other method(s) to mitigate the risk of unauthorized use.

Section 2.1: Examples of evidence for Section 2.1 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of installed security patch(es); memoranda, electronic mail, policies or contracts from parties other than the Responsible Entity that identify the security patching process or vulnerability mitigation performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail, system documentation or contracts that identifies acceptance by the Responsible Entity that the practices of the party other than the Responsible Entity are acceptable; or documentation of other method(s) to mitigate software vulnerabilities for Transient Cyber Asset(s) managed by a party other than the Responsible Entity. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the risk from unpatched software, evidence may include documentation by the Responsible Entity or the party other than the Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Section 2.2: Examples of evidence for Section 2.2 may include, but are not limited to, documentation from change management systems, electronic mail or procedures that document a review of the installed antivirus update level; memoranda, electronic mail, system documentation, policies or contracts from the party other than the Responsible Entity that identify the antivirus update process, the use of application whitelisting, use of live of operating systems or system hardening performed by the party other than the Responsible Entity; evidence from change management systems, electronic mail or contracts that identifies the Responsible Entity's acceptance that the practices of the party other than the Responsible Entity are acceptable; or documentation of other method(s) to mitigate malicious code for Transient Cyber Asset(s) managed by a party other than the Responsible Entity. If a Transient Cyber Asset does not have the capability to use method(s) that mitigate the introduction of malicious code, evidence may include documentation by the Responsible Entity or the party other than the Responsible Entity that identifies that the Transient Cyber Asset does not have the capability.

Section 2.3: Examples of evidence for Section 2.3 may include, but are not limited to, documentation from change management systems, electronic mail, or contracts that identifies a review to determine whether additional mitigations are necessary and that they have been implemented prior to connecting the Transient Cyber Asset managed by a party other than the Responsible Entity.

Section 3.1: Examples of evidence for Section 3.1 may include, but are not limited to, documentation from asset management systems, human resource management systems, forms or spreadsheets that shows authorization of Removable Media. The documentation must identify Removable Media, individually or by group of Removable Media, along with the authorized users,

either individually or by group or role, and the authorized locations, either individually or by group.

Section 3.2: Examples of evidence for Section 3.2 may include, but are not limited to, documented process(es) of the method(s) used to mitigate malicious code such as results of scan settings for Removable Media, or implementation of on-demand scanning. Documented process(es) for the method(s) used for mitigating the threat of detected malicious code on Removable Media, such as logs from the method(s) used to detect malicious code that show the results of scanning and that show mitigation of detected malicious code on Removable Media or documented confirmation by the entity that the Removable Media was deemed to be free of malicious code.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in Section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in Section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in Section 4.1, that is subject to the requirements of the standard. As specified in the exemption section 4.2.3.5, this standard does not apply to Responsible Entities that do not have High Impact or Medium Impact BES Cyber Systems under CIP-002-5.1's categorization. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards.

Requirement R1:

Baseline Configuration

The concept of establishing a Cyber Asset's baseline configuration is meant to provide clarity on requirement language found in previous CIP standard versions. Modification of any item within an applicable Cyber Asset's baseline configuration provides the triggering mechanism for when entities must apply change management processes.

Baseline configurations in CIP-010 consist of five different items: Operating system/firmware, commercially available software or open-source application software, custom software, logical network accessible port identification, and security patches. Operating system information identifies the software and version that is in use on the Cyber Asset. In cases where an independent operating system does not exist (such as for a protective relay), then firmware information should be identified. Commercially available or open-source application software identifies applications that were intentionally installed on the cyber asset. The use of the term "intentional" was meant to ensure that only software applications that were determined to be necessary for Cyber Asset use should be included in the baseline configuration. The SDT does not intend for notepad, calculator, DLL, device drivers, or other applications included in an operating system package as commercially available or open-source application software to be included. Custom software installed may include scripts developed for local entity functions or other custom software developed for a specific task or function for the entity's use. If

additional software was intentionally installed and is not commercially available or open-source, then this software could be considered custom software. If a specific device needs to communicate with another device outside the network, communications need to be limited to only the devices that need to communicate per the requirement in CIP-007-6. Those ports which are accessible need to be included in the baseline. Security patches applied would include all historical and current patches that have been applied on the cyber asset. While CIP-007-6 Requirement R2, Part 2.1 requires entities to track, evaluate, and install security patches, CIP-010 Requirement R1, Part 1.1.5 requires entities to list all applied historical and current patches.

Further guidance can be understood with the following example that details the baseline configuration for a serial-only microprocessor relay:

Asset #051028 at Substation Alpha

- R1.1.1 – Firmware: [MANUFACTURER]-[MODEL]-XYZ-1234567890-ABC
- R1.1.2 – Not Applicable
- R1.1.3 – Not Applicable
- R1.1.4 – Not Applicable
- R1.1.5 – Patch 12345, Patch 67890, Patch 34567, Patch 437823

Also, for a typical IT system, the baseline configuration could reference an IT standard that includes configuration details. An entity would be expected to provide that IT standard as part of their compliance evidence.

Cyber Security Controls

The use of cyber security controls refers specifically to controls referenced and applied according to CIP-005 and CIP-007. The concept presented in the relevant requirement sub-parts in CIP-010 R1 is that an entity is to identify/verify controls from CIP-005 and CIP-007 that could be impacted for a change that deviates from the existing baseline configuration. The SDT does not intend for Responsible Entities to identify/verify all controls located within CIP-005 and CIP-007 for each change. The Responsible Entity is only to identify/verify those control(s) that could be affected by the baseline configuration change. For example, changes that affect logical network ports would only involve CIP-007 R1 (Ports and Services), while changes that affect security patches would only involve CIP-007 R2 (Security Patch Management). The SDT chose not to identify the specific requirements from CIP-005 and CIP-007 in CIP-010 language as the intent of the related requirements is to be able to identify/verify any of the controls in those standards that are affected as a result of a change to the baseline configuration. The SDT believes it possible that all requirements from CIP-005 and CIP-007 may be identified for a

major change to the baseline configuration, and therefore, CIP-005 and CIP-007 was cited at the standard-level versus the requirement-level.

Test Environment

The Control Center test environment (or production environment where the test is performed in a manner that minimizes adverse effects) should model the baseline configuration, but may have a different set of components. For instance, an entity may have a BES Cyber System that runs a database on one component and a web server on another component. The test environment may have the same operating system, security patches, network accessible ports, and software, but have both the database and web server running on a single component instead of multiple components.

Additionally, the Responsible Entity should note that wherever a test environment (or production environment where the test is performed in a manner that minimizes adverse effects) is mentioned, the requirement is to "model" the baseline configuration and not duplicate it exactly. This language was chosen deliberately in order to allow for individual elements of a BES Cyber System at a Control Center to be modeled that may not otherwise be able to be replicated or duplicated exactly; such as, but not limited to, a legacy map-board controller or the numerous data communication links from the field or to other Control Centers (such as by ICCP).

Software Integrity and Authenticity

The concept of verifying software integrity and authenticity is a key control in preventing the introduction of malware or counterfeit software. This objective is intended to reduce the likelihood that an attacker could exploit legitimate vendor patch management processes to deliver compromised software updates or patches to a BES Cyber System. The intent of the SDT is to provide controls for verifying the baseline elements that are updated by vendors. It is important to note that this is not limited to only security patches. That is why the requirement was not placed in CIP-007 - Security Patch Management.

NIST SP-800-161 includes a number of security controls, which, when taken together, reduce the probability of a successful "Watering Hole" or similar cyber attack in the industrial control system environment and thus could assist in addressing this objective. For example, in the System and Information Integrity (SI) control family, control SI-7 suggests that the integrity of information systems and obtaining software directly from the developer. In the Configuration Management (CM) control family, control CM-5(3) requires that the information system prevent the installation of firmware of software without the verification that the component has been digitally signed to ensure that the hardware and software components are genuine and valid. NIST SP-800-161, while not meant to be definitive, provides examples of controls for addressing this objective. Other controls also could meet this objective.

It is not the intent of the SDT to require a verification of each source or software update at the time it is obtained. It is sufficient to establish the reliable source and software update once. This will allow automated solutions to be implemented to obtain frequent updates such as patches.

Requirement R2:

The SDT's intent of R2 is to require automated monitoring of the BES Cyber System. However, the SDT understands that there may be some Cyber Assets where automated monitoring may not be possible (such as a GPS time clock). For that reason, automated technical monitoring was not explicitly required, and a Responsible Entity may choose to accomplish this requirement through manual procedural controls.

Requirement R3:

The Responsible Entity should note that the requirement provides a distinction between paper and active vulnerability assessments. The justification for this distinction is well-documented in FERC Order No. 706 and its associated Notice of Proposed Rulemaking. In developing their vulnerability assessment processes, Responsible Entities are strongly encouraged to include at least the following elements, several of which are referenced in CIP-005 and CIP-007:

Paper Vulnerability Assessment:

1. Network Discovery - A review of network connectivity to identify all Electronic Access Points to the Electronic Security Perimeter.
2. Network Port and Service Identification - A review to verify that all enabled ports and services have an appropriate business justification.
3. Vulnerability Review - A review of security rule-sets and configurations including controls for default accounts, passwords, and network management community strings.
4. Wireless Review - Identification of common types of wireless networks (such as 802.11a/b/g/n) and a review of their controls if they are in any way used for BES Cyber System communications.

Active Vulnerability Assessment:

1. Network Discovery - Use of active discovery tools to discover active devices and identify communication paths in order to verify that the discovered network architecture matches the documented architecture.
2. Network Port and Service Identification – Use of active discovery tools (such as Nmap) to discover open ports and services.
3. Vulnerability Scanning – Use of a vulnerability scanning tool to identify network accessible ports and services along with the identification of known vulnerabilities associated with services running on those ports.
4. Wireless Scanning – Use of a wireless scanning tool to discover wireless signals and networks in the physical perimeter of a BES Cyber System. Serves to identify unauthorized wireless devices within the range of the wireless scanning tool.

In addition, Responsible Entities are strongly encouraged to review NIST SP800-115 for additional guidance on how to conduct a vulnerability assessment.

Requirement R4:

Because most BES Cyber Assets and BES Cyber Systems are isolated from external public or untrusted networks, Transient Cyber Assets and Removable Media are a means for cyber-attack. Transient Cyber Assets and Removable Media are often the only way to transport files to and from secure areas to maintain, monitor, or troubleshoot critical systems. To protect the BES Cyber Assets and BES Cyber Systems, entities are required to document and implement a plan for how they will manage the use of Transient Cyber Assets and Removable Media. The approach of defining a plan allows the Responsible Entity to document the processes that are supportable within its organization and in alignment with its change management processes.

Transient Cyber Assets and Removable Media are those devices connected temporarily to: (1) a BES Cyber Asset, (2) a network within an ESP, or (3) a Protected Cyber Asset. Transient Cyber Assets and Removable Media do not provide BES reliability services and are not part of the BES Cyber Asset to which they are connected. Examples of these temporarily connected devices include, but are not limited to:

- Diagnostic test equipment;
- Packet sniffers;
- Equipment used for BES Cyber System maintenance;
- Equipment used for BES Cyber System configuration; or
- Equipment used to perform vulnerability assessments.

Transient Cyber Assets can be one of many types of devices from a specially-designed device for maintaining equipment in support of the BES to a platform such as a laptop, desktop, or tablet that may just interface with or run applications that support BES Cyber Systems and is capable of transmitting executable code. Removable Media in scope of this requirement can be in the form of floppy disks, compact disks, USB flash drives, external hard drives, and other flash memory cards/drives that contain nonvolatile memory.

While the definitions of Transient Cyber Asset and Removable Media include a conditional provision that requires them to be connected for 30 days or less, Section 1.1 of Attachment 1 allows the Responsible Entity to include provisions in its plan(s) that allow continuous or on-demand treatment and application of controls independent of the connected state. Please note that for on-demand treatment, the requirements only apply when Transient Cyber Assets and Removable Media are being connected to a BES Cyber System or Protected Cyber Asset. Once the transient device is disconnected, the requirements listed herein are not applicable until that Transient Cyber Asset or Removable Media is to be reconnected to the BES Cyber Asset or Protected Cyber Asset.

The attachment was created to specify the capabilities and possible security methods available to Responsible Entities based upon asset type, ownership, and management.

With the list of options provided in Attachment 1 for each control area, the entity has the discretion to use the option(s) that is most appropriate. This includes documenting its approach for how and when the entity manages or reviews the Transient Cyber Asset under its control or under the control of parties other than the Responsible Entity. The entity should avoid implementing a security function that jeopardizes reliability by taking actions that would negatively impact the performance or support of the Transient Cyber Asset, BES Cyber Asset, or Protected Cyber Asset.

Vulnerability Mitigation

The terms “mitigate”, “mitigating”, and “mitigation” are used in the sections in Attachment 1 to address the risks posed by malicious code, software vulnerabilities, and unauthorized use when connecting Transient Cyber Assets and Removable Media. Mitigation in this context does not require that each vulnerability is individually addressed or remediated, as many may be unknown or not have an impact on the system to which the Transient Cyber Asset or Removable Media is connected. Mitigation is meant to reduce security risks presented by connecting the Transient Cyber Asset.

Per Transient Cyber Asset Capability

As with other CIP standards, the requirements are intended for an entity to use the method(s) that the system is capable of performing. The use of “per Transient Cyber Asset capability” is to eliminate the need for a Technical Feasibility Exception when it is understood that the device cannot use a method(s). For example, for malicious code, many types of appliances are not capable of implementing antivirus software; therefore, because it is not a capability of those types of devices, implementation of the antivirus software would not be required for those devices.

Requirement R4, Attachment 1, Section 1 - Transient Cyber Asset(s) Managed by the Responsible Entity

Section 1.1: Entities have a high level of control for the assets that they manage. The requirements listed herein allow entities the flexibility to either pre-authorize an inventory of devices or authorize devices at the time of connection or use a combination of these methods. The devices may be managed individually or by group.

Section 1.2: Entities are to document and implement their process(es) to authorize the use of Transient Cyber Assets for which they have direct management. The Transient Cyber Assets may be listed individually or by asset type. To meet this requirement part, the entity is to document the following:

1.2.1 User(s), individually or by group/role, allowed to use the Transient Cyber Asset(s). This can be done by listing a specific person, department, or job function. Caution: consider whether these user(s) must also have authorized electronic access to the applicable system in accordance with CIP-004.

1.2.2 Locations where the Transient Cyber Assets may be used. This can be done by listing a specific location or a group of locations.

1.2.3 The intended or approved use of each individual, type, or group of Transient Cyber Asset. This should also include the software or application packages that are authorized with the purpose of performing defined business functions or tasks (e.g., used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes), and approved network interfaces (e.g., wireless, including near field communication or Bluetooth, and wired connections). Activities, and software or application packages, not specifically listed as acceptable should be considered as prohibited. It may be beneficial to educate individuals through the CIP-004 Security Awareness Program and Cyber Security Training Program about authorized and unauthorized activities or uses (e.g., using the device to browse the Internet or to check email or using the device to access wireless networks in hotels or retail locations).

Entities should exercise caution when using Transient Cyber Assets and ensure they do not have features enabled (e.g., wireless or Bluetooth features) in a manner that would allow the device to bridge an outside network to an applicable system. Doing so would cause the Transient Cyber Asset to become an unauthorized Electronic Access Point in violation of CIP-005, Requirement R1.

Attention should be paid to Transient Cyber Assets that may be used for assets in differing impact areas (i.e., high impact, medium impact, and low impact). These impact areas have differing levels of protection under the CIP requirements, and measures should be taken to prevent the introduction of malicious code from a lower impact area. An entity may want to consider the need to have separate Transient Cyber Assets for each impact level.

Section 1.3: Entities are to document and implement their process(es) to mitigate software vulnerabilities posed by unpatched software through the use of one or more of the protective measures listed. This needs to be applied based on the capability of the device. Recognizing there is a huge diversity of the types of devices that can be included as Transient Cyber Assets and the advancement in software vulnerability management solutions, options are listed that include the alternative for the entity to use a technology or process that effectively mitigates vulnerabilities.

- Security patching, including manual or managed updates provides flexibility to the Responsible Entity to determine how its Transient Cyber Asset(s) will be used. It is possible for an entity to have its Transient Cyber Asset be part of an enterprise patch process and receive security patches on a regular schedule or the entity can verify and apply security patches prior to connecting the Transient Cyber Asset to an applicable Cyber Asset. Unlike CIP-007, Requirement R2, there is no expectation of creating dated mitigation plans or other documentation other than what is necessary to identify that the Transient Cyber Asset is receiving appropriate security patches.
- Live operating system and software executable only from read-only media is provided to allow a protected operating system that cannot be modified to deliver malicious software. When entities are creating custom live operating systems, they

should check the image during the build to ensure that there is not malicious software on the image.

- System hardening, also called operating system hardening, helps minimize security vulnerabilities by removing all non-essential software programs and utilities and only installing the bare necessities that the computer needs to function. While other programs may provide useful features, they can provide "back-door" access to the system, and should be removed to harden the system.
- When selecting to use other methods that mitigate software vulnerabilities to those listed, entities need to have documentation that identifies how the other method(s) meet the software vulnerability mitigation objective.

Section 1.4: Entities are to document and implement their process(es) to mitigate malicious code through the use of one or more of the protective measures listed. This needs to be applied based on the capability of the device. As with vulnerability management, there is diversity of the types of devices that can be included as Transient Cyber Assets and the advancement in malicious code protections. When addressing malicious code protection, the Responsible Entity should address methods deployed to deter, detect, or prevent malicious code. If malicious code is discovered, it must be removed or mitigated to prevent it from being introduced into the BES Cyber Asset or BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident.

- Antivirus software, including manual or managed updates of signatures or patterns, provides flexibility just as with security patching, to manage Transient Cyber Asset(s) by deploying antivirus or endpoint security tools that maintain a scheduled update of the signatures or patterns. Also, for devices that do not regularly connect to receive scheduled updates, entities may choose to scan the Transient Cyber Asset prior to connection to ensure no malicious software is present.
- Application whitelisting is a method of authorizing only the applications and processes that are necessary on the Transient Cyber Asset. This reduces the opportunity that malicious software could become resident, much less propagate, from the Transient Cyber Asset to the BES Cyber Asset or BES Cyber System.
- Restricted communication to limit the exchange of data to only the Transient Cyber Asset and the Cyber Assets to which it is connected by restricting or disabling serial or network (including wireless) communications on a managed Transient Cyber Asset can be used to minimize the opportunity to introduce malicious code onto the Transient Cyber Asset while it is not connected to BES Cyber Systems. This renders the device unable to communicate with devices other than the one to which it is connected.
- When selecting to use other methods that mitigate the introduction of malicious code to those listed, entities need to have documentation that identifies how the other method(s) meet the mitigation of the introduction of malicious code objective.

Section 1.5: Entities are to document and implement their process(es) to protect and evaluate Transient Cyber Assets to ensure they mitigate the risks that unauthorized use of the Transient Cyber Asset may present to the BES Cyber System. The concern addressed by this section is the possibility that the Transient Cyber Asset could be tampered with, or exposed to malware, while not in active use by an authorized person. Physical security of the Transient Cyber Asset is certainly a control that will mitigate this risk, but other tools and techniques are also available. The bulleted list of example protections provides some suggested alternatives.

- For restricted physical access, the intent is that the Transient Cyber Asset is maintained within a Physical Security Perimeter or other physical location or enclosure that uses physical access controls to protect the Transient Cyber Asset.
- Full disk encryption with authentication is an option that can be employed to protect a Transient Cyber Asset from unauthorized use. However, it is important that authentication be required to decrypt the device. For example, pre-boot authentication, or power-on authentication, provides a secure, tamper-proof environment external to the operating system as a trusted authentication layer. Authentication prevents data from being read from the hard disk until the user has confirmed they have the correct password or other credentials. By performing the authentication prior to the system decrypting and booting, the risk that an unauthorized person may manipulate the Transient Cyber Asset is mitigated.
- Multi-factor authentication is used to ensure the identity of the person accessing the device. Multi-factor authentication also mitigates the risk that an unauthorized person may manipulate the Transient Cyber Asset.
- In addition to authentication and pure physical security methods, other alternatives are available that an entity may choose to employ. Certain theft recovery solutions can be used to locate the Transient Cyber Asset, detect access, remotely wipe, and lockout the system, thereby mitigating the potential threat from unauthorized use if the Transient Cyber Asset was later connected to a BES Cyber Asset. Other low tech solutions may also be effective to mitigate the risk of using a maliciously-manipulated Transient Cyber Asset, such as tamper evident tags or seals, and executing procedural controls to verify the integrity of the tamper evident tag or seal prior to use.
- When selecting to use other methods that mitigate the risk of unauthorized use to those listed, entities need to have documentation that identifies how the other method(s) meet the mitigation of the risk of unauthorized use objective.

Requirement R4, Attachment 1, Section 2 - Transient Cyber Asset(s) Managed by a Party Other than the Responsible Entity

The attachment also recognizes the lack of control for Transient Cyber Assets that are managed by parties other than the Responsible Entity. However, this does not obviate the Responsible Entity's responsibility to ensure that methods have been deployed to deter, detect, or prevent

malicious code on Transient Cyber Assets it does not manage. The requirements listed herein allow entities the ability to review the assets to the best of their capability and to meet their obligations.

To facilitate these controls, Responsible Entities may choose to execute agreements with other parties to provide support services to BES Cyber Systems and BES Cyber Assets that may involve the use of Transient Cyber Assets. Entities may consider using the Department of Energy Cybersecurity Procurement Language for Energy Delivery dated April 2014. [1] Procurement language may unify the other party and entity actions supporting the BES Cyber Systems and BES Cyber Assets. CIP program attributes may be considered including roles and responsibilities, access controls, monitoring, logging, vulnerability, and patch management along with incident response and back up recovery may be part of the other party's support. Entities should consider the "General Cybersecurity Procurement Language" and "The Supplier's Life Cycle Security Program" when drafting Master Service Agreements, Contracts, and the CIP program processes and controls.

Section 2.1: Entities are to document and implement their process(es) to mitigate software vulnerabilities through the use of one or more of the protective measures listed.

- Conduct a review of the Transient Cyber Asset managed by a party other than the Responsible Entity to determine whether the security patch level of the device is adequate to mitigate the risk of software vulnerabilities before connecting the Transient Cyber Asset to an applicable system.
- Conduct a review of the other party's security patching process. This can be done either at the time of contracting but no later than prior to connecting the Transient Cyber Asset to an applicable system. Just as with reviewing the security patch level of the device, selecting to use this approach aims to ensure that the Responsible Entity has mitigated the risk of software vulnerabilities to applicable systems.
- Conduct a review of other processes that the other party uses to mitigate the risk of software vulnerabilities. This can be reviewing system hardening, application whitelisting, virtual machines, etc.
- When selecting to use other methods to mitigate software vulnerabilities to those listed, entities need to have documentation that identifies how the other method(s) meet mitigation of the risk of software vulnerabilities.

Section 2.2: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more of the protective measures listed.

- Review the use of antivirus software and signature or pattern levels to ensure that the level is adequate to the Responsible Entity to mitigate the risk of malicious software being introduced to an applicable system.

[1] http://www.energy.gov/oe/downloads/cybersecurity-procurement-language-energy-delivery-april-2014

- Review the antivirus or endpoint security processes of the other party to ensure that their processes are adequate to the Responsible Entity to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of application whitelisting used by the other party to mitigate the risk of introducing malicious software to an applicable system.
- Review the use of live operating systems or software executable only from read-only media to ensure that the media is free from malicious software itself. Entities should review the processes to build the read-only media as well as the media itself.
- Review system hardening practices used by the other party to ensure that unnecessary ports, services, applications, etc. have been disabled or removed. This will limit the chance of introducing malicious software to an applicable system.

Section 2.3: Determine whether additional mitigation actions are necessary, and implement such actions prior to connecting the Transient Cyber Asset managed by a party other than the Responsible Entity. The intent of this section is to ensure that after conducting the selected review from Sections 2.1 and 2.2, if there are deficiencies that do not meet the Responsible Entity's security posture, the other party is required to complete the mitigations prior to connecting their devices to an applicable system.

Requirement R4, Attachment 1, Section 3 - Removable Media

Entities have a high level of control for Removable Media that are going to be connected to their BES Cyber Assets.

Section 3.1: Entities are to document and implement their process(es) to authorize the use of Removable Media. The Removable Media may be listed individually or by type.

- Document the user(s), individually or by group/role, allowed to use the Removable Media. This can be done by listing a specific person, department, or job function. Authorization includes vendors and the entity's personnel. Caution: consider whether these user(s) must have authorized electronic access to the applicable system in accordance with CIP-004.
- Locations where the Removable Media may be used. This can be done by listing a specific location or a group/role of locations.

Section 3.2: Entities are to document and implement their process(es) to mitigate the introduction of malicious code through the use of one or more method(s) to detect malicious code on the Removable Media before it is connected to a BES Cyber Asset. When using the method(s) to detect malicious code, it is expected to occur from a system that is not part of the BES Cyber System to reduce the risk of propagating malicious code into the BES Cyber System network or onto one of the BES Cyber Assets. If malicious code is discovered, it must be removed or mitigated to prevent it from being introduced into the BES Cyber Asset or BES Cyber System. Entities should also consider whether the detected malicious code is a Cyber Security Incident. Frequency and timing of the methods used to detect malicious code were intentionally excluded from the requirement because there are multiple timing scenarios that

can be incorporated into a plan to mitigate the risk of malicious code. The entities must use the method(s) to detect malicious code on Removable Media before it is connected to the BES Cyber Asset. The timing dictated and documented in the entity's plan should reduce the risk of introducing malicious code to the BES Cyber Asset or Protected Cyber Asset.

As a method to detect malicious code, entities may choose to use Removable Media with on-board malicious code detection tools. For these tools, the Removable Media are still used in conjunction with a Cyber Asset to perform the detection. For Section 3.2.1, the Cyber Asset used to perform the malicious code detection must be outside of the BES Cyber System or Protected Cyber Asset.

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 Requirement R1:
The configuration change management processes are intended to prevent unauthorized modifications to BES Cyber Systems.

Rationale for Requirement R2:
The configuration monitoring processes are intended to detect unauthorized modifications to BES Cyber Systems.

Rationale for Requirement R3:
The vulnerability assessment processes are intended to act as a component in an overall program to periodically ensure the proper implementation of cyber security controls as well as to continually improve the security posture of BES Cyber Systems.
The vulnerability assessment performed for this requirement may be a component of deficiency identification, assessment, and correction.

Rationale for R4:
Requirement R4 responds to the directive in FERC Order No. 791, at Paragraphs 6 and 136, to address security-related issues associated with Transient Cyber Assets and Removable Media used on a temporary basis for tasks such as data transfer, vulnerability assessment, maintenance, or troubleshooting. These tools are potential vehicles for transporting malicious code into a facility and subsequently into Cyber Assets or BES Cyber Systems. To mitigate the risks associated with such tools, Requirement R4 was developed to accomplish the following security objectives:

- Preventing unauthorized access or malware propagation to BES Cyber Systems through Transient Cyber Assets or Removable Media; and
- Preventing unauthorized access to BES Cyber System Information through Transient Cyber Assets or Removable Media.

Requirement R4 incorporates the concepts from other CIP requirements in CIP-010~~-2~~ and CIP-007~~-6~~ to help define the requirements for Transient Cyber Assets and Removable Media.

Summary of Changes: All requirements related to Transient Cyber Assets and Removable Media are included within a single standard, CIP-010. Due to the newness of the requirements and definition of asset types, the SDT determined that placing the requirements in a single standard would help ensure that entities were able to quickly identify the requirements for these asset types. A separate standard was considered for these requirements. However, the SDT determined that these types of assets would be used in relation to change management and vulnerability assessment processes and should, therefore, be placed in the same standard as those processes.

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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 19, 2016
SAR posted for comment	October 20 - November 21, 2016
45-day formal comment period with ballot	January 19 - March 6, 2017

Anticipated Actions	Date
45-day formal comment period with ballot	May 2017
NERC Board (Board) adoption	August 2017

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:** **Cyber Security - Supply Chain Risk Management**

2. **Number:** **CIP-013-1**

3. **Purpose:** To mitigate cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1. Balancing Authority

   4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

   4.1.2.1. Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:

   4.1.2.1.1. Is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

   4.1.2.1.2. Performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

   4.1.2.2. Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.3. Generator Operator

   4.1.4. Generator Owner

   4.1.5. Reliability Coordinator

   4.1.6. Transmission Operator

   4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. Is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. Performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers

4.2.2.1. All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-013-1:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3. 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.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

4.2.3.5. Responsible Entities that identify that they have no BES Cyber Systems categorized as high impact or medium impact according to the identification and categorization process required by CIP-002-5, or any subsequent version of that Reliability Standard.

5. Effective Date: See Implementation Plan for Project 2016-03.

B. Requirements and Measures

Rationale for Requirement R1:
The proposed Requirement addresses Order No. 829 directives for entities to implement a plan(s) that includes processes for mitigating cyber security risks in the supply chain. The plan(s) is required to address the following four objectives (Order No. 829 at P. 45):

(1) Software integrity and authenticity;
(2) Vendor remote access;
(3) Information system planning; and
(4) Vendor risk management and procurement controls.

The cyber security risk management plan(s) specified in Requirement R1 apply to high and medium impact BES Cyber Systems.

Implementation of the cyber security risk management plan(s) does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders), consistent with Order No. 829 (P. 36).

Requirement R1 Part 1.1 addresses the directive in Order No. 829 for identification and documentation of cyber security risks in the planning and development processes related to the procurement of BES Cyber Systems (P. 56). The security objective is to ensure entities consider cyber security risks to the BES from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another vendor(s); and options for mitigating these risks when planning for BES Cyber Systems.

Requirement R1 Part 1.2 addresses the directive in Order No. 829 for procurement controls to address the provision and verification of security concepts in future contracts for BES Cyber Systems (P. 59). The objective of Part 1.2 is for entities to include these topics in their plans so that procurement and contract negotiation processes address the applicable risks. Implementation of elements contained in the entity's plan related to Part 1.2 may be accomplished through the entity's procurement and contract negotiation

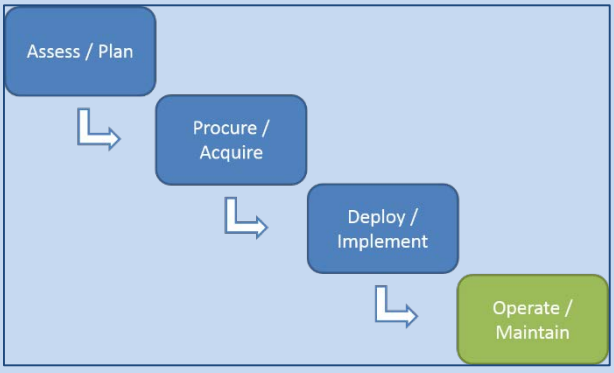
processes. For example, entities can implement the plan by including applicable procurement items from their plan in Requests for Proposals (RFPs) and in negotiations with vendors. Obtaining specific controls in the negotiated contract may not be feasible and is not considered failure to implement an entity's plan. Although the expectation is that Responsible Entities would enforce the security-related provisions in the contract based on the terms and conditions of that contract, such contract enforcement and vendor performance or adherence to the negotiated contract is not subject to this Reliability Standard.

The objective of verifying software integrity and authenticity (Part 1.2.5) is to help ensure that software installed on BES Cyber Systems is not modified prior to installation without the awareness of the software supplier and is not counterfeit. Part 1.2.5 is not an operational requirement for entities to perform such verification; instead, it requires entities to address the software integrity and authenticity issue in its contracting process to provide the entity the means by which to perform such verification under CIP-010-3.

The term *vendor(s)* as used in the standard is limited to those persons, companies, or other organizations with whom the Responsible Entity, or its affiliates, contract with to supply BES Cyber Systems and related services. It does not include other NERC registered entities providing reliability services (e.g., Balancing Authority or Reliability Coordinator services pursuant to NERC Reliability Standards). A *vendor,* as used in the standard, may include: (i) developers or manufacturers of information systems, system components, or information system services; (ii) product resellers; or (iii) system integrators.

Collectively, the provisions of CIP-013-1 address an entity's controls for managing cyber security risks to BES Cyber Systems during the planning, acquisition, and deployment phases of the system life cycle, as shown below.

Notional BES Cyber System Life Cycle



R1. Each Responsible Entity shall ~~implement~~ develop one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems. ~~that address controls for mitigating cyber security risks to BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets.~~ The plan(s) shall ~~address~~include: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** The use of controls in BES Cyber System planning and development to:~~

~~**1.1.1.** Identify and assess risk(s) during the procurement and deployment of vendor products and services; and~~

~~**1.1.2.** Evaluate methods to address identified risk(s).~~

1.1. One or more process(es) used in planning for the procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another vendor(s).

~~**1.2.**~~

~~The use of controls in procuring vendor product(s) or service(s) that address the following items, to the extent each item applies to the Responsible Entity's BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets:~~ ~~The use of~~

1.2. One or more process(es) used in procuring BES Cyber Systems that address the following, as applicable:

1.2.1. ~~Process(es) for notification of vendor security events;~~ Notification by the vendor of vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;

~~**1.2.1.**~~**1.2.2.** Coordination of responses to vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;

~~**1.2.2.**~~**1.2.3.** ~~Process(es) for notification when vendor employee remote or onsite access should no longer be granted;~~ Notification by vendors when remote or onsite access should no longer be granted to vendor representatives;

~~**1.2.3.**~~**1.2.4.** ~~Process(es) for disclosure of known vulnerabilities;~~ Disclosure by vendors of known vulnerabilities;

~~**1.2.4.** Coordination of response to vendor-related cyber security incidents;~~

1.2.5. ~~Process(es) for verifying software integrity and authenticity of all software and patches that are intended for use;~~ Verification of software

integrity and authenticity of all software and patches provided by the vendor for use in the BES Cyber System; and

1.2.6. ~~Coordination of remote access controls for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s); and~~ Coordination of controls for (i) vendor-initiated Interactive Remote Access, and (ii) system-to-system remote access with a vendor(s).

~~**1.2.6.**~~**1.2.7.**

~~Other process(es) to address risk(s) as determined in Part 1.1.2, if applicable.~~

M1. Evidence shall include ~~(i)~~ one or more documented supply chain cyber security risk management plan(s) ~~that address controls for mitigating cyber security risks~~ as specified in the Requirement.~~; and (ii) documentation to demonstrate implementation of the supply chain cyber security risk management plan(s), which could include, but is not limited to, written agreements in electronic or hard copy format, correspondence, policy documents, or working documents that demonstrate implementation of the cyber security risk management plan(s).~~

R2. Each Responsible Entity shall implement its supply chain cyber security risk management plan(s) specified in Requirement R1 *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*.

Note: Implementation of the plan does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the following issues are beyond the scope of Requirement R2: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.

~~**M1.**~~**M2.** Evidence shall include documentation to demonstrate implementation of the supply chain cyber security risk management plan(s), which could include, but is not limited to, correspondence, policy documents, or working documents that demonstrate use of the supply chain cyber security risk management plan.

Rationale for Requirement ~~R2~~R3:
The proposed requirement addresses Order No. 829 directives for entities to periodically reassess selected supply chain cyber security risk management controls (P. 46).

~~Order No. 829 also directs that the p~~Entities perform periodic assessment ~~"ensure that the required~~to keep plans ~~remains~~ up-to-date and~~,~~ address~~ing~~ current and emerging supply chain-related concerns and vulnerabilities.~~" (P. 47).~~ Examples of sources of information that the entity could consider~~s~~ include guidance or information issued by:

- NERC or the E-ISAC
- ICS-CERT
- Canadian Cyber Incident Response Centre (CCIRC)

~~R2.~~R3. Each Responsible Entity shall review and obtain CIP Senior Manager or delegate approval ~~update, as necessary,~~of its supply chain cyber security risk management plan(s) specified in Requirement R1 at least once every 15 calendar months~~, which shall include:~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~2.1. Evaluation of revisions, if any, to address applicable new supply chain security risks and mitigation measures; and~~

~~2.2. Obtaining CIP Senior Manager or delegate approval.~~

~~M2.~~M3. Evidence shall include the dated supply chain cyber security risk management plan(s) approved by the CIP Senior Manager or delegate(s) and additional evidence to demonstrate review of the supply chain cyber security risk management plan(s~~) and evaluation of revisions~~). ~~, if any, to address applicable new supply chain security risks and mitigation measures as specified in the Requirement.~~ Evidence may include, but is not limited to, policy documents, revision history, records of review, or workflow evidence from a document management system that indicate review of supply chain risk management plan(s) at least once every 15 calendar months; and documented approval by the CIP Senior Manager or delegate.

~~R3. Each Responsible Entity shall implement one or more documented process(es) for verifying the integrity and authenticity of the following software and firmware before being placed in operation on high and medium impact BES Cyber Systems: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~3.1. Operating System(s);~~

~~3.2. Firmware;~~

~~3.3. Commercially available or open-source application software; and~~

~~3.4. Patches, updates, and upgrades to 3.1 through 3.3.~~

~~M3. Evidence shall include (i) a documented process(es) for verifying the integrity and authenticity of software and firmware before being placed in operation on high and medium impact BES Cyber Systems as specified in the Requirement; and (ii) evidence to show that the process was implemented. This evidence may include, but is not limited to, documentation that the entity performed the actions contained in the process to verify the integrity and authenticity of software and firmware and any patches, updates, and upgrades to software and firmware prior to installation on high and medium impact BES Cyber Systems.~~

R4. Each Responsible Entity shall implement one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems. The process(es) shall provide the following for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s): *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

4.1. Authorization of remote access by the Responsible Entity;

4.2. Logging and monitoring of remote access sessions to detect unauthorized activity; and

4.3. Disabling or otherwise responding to unauthorized activity during remote access sessions.

M4. Evidence shall include (i) a documented process(es) for controlling vendor remote access as specified in the Requirement; and (ii) evidence to show that the process was implemented. This evidence may include, but is not limited to, documentation of authorization of vendor remote access; hard copy or electronic logs of vendor-initiated Interactive Remote Access and system-to-system remote access sessions; hard copy or electronic listing of alert capabilities applicable to vendor remote access of the BES Cyber System; or records of response to unauthorized vendor remote access.

R5. Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall have one or more documented cyber security policies, which shall be reviewed and approved by the CIP Senior Manager or delegate at least once every 15 calendar months, that address the following topics for its low impact BES Cyber Systems: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

5.1. Integrity and authenticity of software and firmware and any patches, updates, and upgrades to software and firmware; and

5.2. Controlling vendor-initiated remote access, including system-to-system remote access with vendor(s).

M5. Evidence may include, but is not limited to, policy documents; revision history, records of review, or workflow evidence from a document management system that indicate review of each cyber security policy at least once every 15 calendar months; and documented approval by the CIP Senior Manager or delegate for each cyber security policy.

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 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.

- Each Responsible Entity shall retain evidence of each requirement in this 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 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.	The Responsible Entity developed one or more documented supply chain cyber security risk management plan(s) which include the use of processes in planning for procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the BES as specified in Part 1.1, and include the use of process(es) for procuring BES Cyber systems as specified in Part 1.2, but the plans do not include one of the elements in Part 1.2.1 through Part 1.2.6. ~~N/A~~	The Responsible Entity developed one or more documented supply chain cyber security risk management plan(s) which include the use of processes in planning for procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the BES as specified in Part 1.1, and include the use of process(es) for procuring BES Cyber systems as specified in Part 1.2, but the plans do not include two or more of the elements in Part 1.2.1 through Part 1.2.6. ~~N/A~~	The Responsible Entity developed one or more documented supply chain cyber security risk management plan(s), but the plan(s) did not include the use of processes in planning for procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the BES as specified in Part 1.1, or the plan(s) did not include the use of process(es) for procuring BES Cyber systems as specified in Part 1.2.	The Responsible Entity developed one or more documented supply chain cyber security risk management plan(s), but the plan(s) did not include the use of processes in planning for procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the BES as specified in Part 1.1, and the plan(s) did not include the use of process(es) for procuring BES Cyber systems as specified in Part 1.2. OR The Responsible Entity did not develop ~~The Responsible Entity did not implement~~one or more documented supply chain cyber security risk management plan(s) as specified in the Requirement.

R2.	N/A ~~The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 15 calendar months but less than or equal to 16 calendar months since the previous review as specified in the Requirement.~~	N/A ~~The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 16 calendar months but less than or equal to 17 calendar months since the previous review as specified in the Requirement.~~	N/A ~~The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 17 calendar months but less than or equal to 18 calendar months since the previous review as specified in the Requirement.~~	The Responsible Entity did not implement its supply chain cyber security risk management plan(s) as specified in the requirement.~~The Responsible Entity did not review and update, as necessary, its supply chain cyber security risk management plan(s) and obtain CIP Senior Manager or delegate approval within 18 calendar months of the previous review as specified in the Requirement.~~
R3.	The Responsible Entity reviewed and obtained CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) but did so more than 15 calendar months but less than or equal to 16 calendar months since the previous review as specified in the Requirement.~~N/A~~	The Responsible Entity reviewed and obtained CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) but did so more than 16 calendar months but less than or equal to 17 calendar months since the previous review as specified in the Requirement.~~N/A~~	The Responsible Entity reviewed and obtained CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) but did so more than 17 calendar months but less than or equal to 18 calendar months since the previous review as specified in the Requirement.~~N/A~~	The Responsible Entity did not review and obtain CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) within 18 calendar months of the previous review as specified in the Requirement.~~The Responsible Entity did not implement one or more documented process(es) for verifying the integrity and authenticity of software and~~

				~~firmware before being placed in operation on high and medium impact BES Cyber Systems as specified in the Requirement.~~

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents.

Version History

Version	Date	Action	Change Tracking
1	TBD	Respond to FERC Order No. 829.	NA

Standard Attachments

None

Guidelines and Technical Basis

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 adoption, the text from the rationale text boxes was moved to this section.

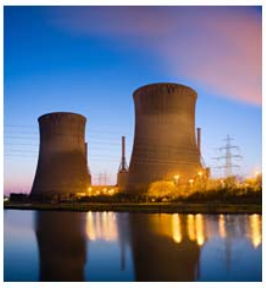
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT

Cyber Security Supply Chain Risk Management Plans

Implementation Guidance for CIP-013-1

RELIABILITY | ACCOUNTABILITY



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Introduction

On July 21, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 829 directing the North American Electric Reliability Corporation (NERC) to develop a new or modified Reliability Standard that addresses cyber security supply chain risk management for industrial control system hardware, software, and computing and networking services associated with Bulk Electric System (BES) operations as follows:

> [The Commission directs] NERC to develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations. The new or modified Reliability Standard should address the following security objectives, [discussed in detail in the Order]: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls.

Reliability Standard **CIP-013-1 – Cyber Security – Supply Chain Risk Management** addresses the relevant cyber security supply chain risks in the planning, acquisition, and deployment phases of the system life cycle for high and medium impact BES Cyber Systems[1].

This implementation guidance provides considerations for implementing the requirements in CIP-013-1 and examples of approaches that responsible entities could use to meet the requirements. The examples do not constitute the only approach to complying with CIP-013-1. Responsible Entities may choose alternative approaches that better fit their situation.

[1] Responsible Entities identify high and medium impact BES Cyber Systems according to the identification and categorization process required by CIP-002-5, or subsequent version of that standard.

Requirement R1

R1. *Each Responsible Entity shall develop one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems. The plan(s) shall include:*

1.1. *One or more process(es) used in planning for the procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another vendor(s).*

1.2. *One or more process(es) used in procuring BES Cyber Systems that address the following, as applicable:*

1.2.1. *Notification by the vendor of vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*

1.2.2. *Coordination of responses to vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*

1.2.3. *Notification by vendors when remote or onsite access should no longer be granted to vendor representatives;*

1.2.4. *Disclosure by vendors of known vulnerabilities;*

1.2.5. *Verification of software integrity and authenticity of all software and patches provided by the vendor for use in the BES Cyber System; and*

1.2.6. *Coordination of controls for (i) vendor-initiated Interactive Remote Access, and (ii) system-to-system remote access with a vendor(s).*

General Considerations for R1

The following are some general considerations for Responsible Entities as they implement Requirement R1:

First, in developing their supply chain cyber security risk management plan(s), Responsible entities should consider how to leverage the various components and phases of their processes (e.g. defined requirements, request for proposal, bid evaluation, external vendor assessment tools and data, third party certifications and audit reports, etc.) to help them meet the objective of Requirement R1 and give them flexibility to negotiate contracts with vendors to efficiently mitigate risks. Focusing solely on the negotiation of specific contract terms could have unintended consequences, including significant and unexpected cost increases for the product or service or vendors refusing to enter into contracts.

Additionally, a Responsible Entity may not have the ability to obtain each of its desired cyber security controls in its contract with each of its vendors. Factors such as competition, limited supply sources, expense, criticality of the product or service, and maturity of the vendor or product line could affect the terms and conditions ultimately negotiated by the parties and included in a contract. This variation in contract terms is anticipated and, in turn, the note in Requirement R2 provides that the actual terms and conditions of the contract are outside the scope of Reliability Standard CIP-013-1.

Note: Implementation of the plan does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the

following issues are beyond the scope of Requirement R2: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.

The focus of Requirement R1 is on the steps the Responsibility Entity takes to consider cyber security risks from vendor products or services during BES Cyber System planning and procurement. In the event the vendor is unwilling to engage in the negotiation process for cyber security controls, the Responsible Entity could explore other sources of supply or mitigating controls to reduce the risk to the BES cyber systems, as the Responsible Entity's circumstances allow.

In developing and implementing its supply chain cyber security risk management plan, a Responsible Entity may consider identifying and prioritizing security controls based on the cyber security risks presented by the vendor and the criticality of the product or service to reliable operations. For instance, Responsible Entities may establish a baseline set of controls for given products or services that a vendor must meet prior to transacting with that vendor for those products and services (i.e., "must-have controls"). As risks differ between products and services, the baseline security controls – or "must haves" – may differ for the various products and services the Responsible Entities procures for its BES Cyber Systems. This risk-based approach could help create efficiencies in the Responsible Entity's procurement processes while meeting the security objectives of Requirement R1.

The objective of addressing the verification of software integrity and authenticity during the procurement phase of BES Cyber System(s) (Part 1.2.5) is to identify the capability of the vendor(s) to ensure that the software installed on BES Cyber System(s) is trustworthy. Part 1.2.5 is not an operational requirement for Responsible Entities to perform the verification; instead, Part 1.2.5 is aimed at identifying during the procurement phase the vendor's capability to provide software integrity and authenticity assurance and establish vendor performance based on the vendor's capability in order to implement CIP-010-3, Requirement R1, Part 1.6.

Implementation Guidance for R1

Responsible entities use various processes as they plan to procure BES Cyber Systems. Below are some examples of approaches to comply with this requirement:

R1. *Each Responsible Entity shall develop one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems. The plan(s) shall include:*

- The Responsible Entity could establish one or more documents explaining the process by which the Responsible Entity will address supply chain cyber security risk management for high and medium impact BES Cyber Systems. To achieve the flexibility needed for supply chain cyber security risk management, Responsible Entities can use a "risk-based approach". One element of, or approach to, a risk-based cyber security risk management plan is **system-based**, focusing on specific controls for high and medium impact BES Cyber Systems to address the risks presented in procuring those systems or services for those systems. A risk-based approach could also be **vendor-based**, focusing on the risks posed by various vendors of its BES Cyber Systems. Entities may combine both of these approaches into their plans. This flexibility is important to account for the varying "needs and characteristics of responsible entities and the diversity of BES Cyber System environments, technologies, and risk (FERC Order No. 829 P 44)."

1.1. *One or more process(es) used in planning for the procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another vendor(s).*

A Responsible Entity could document in its supply chain cyber security risk management plan one or more processes that it will use when planning for the procurement of BES Cyber Systems to identify and assess cyber security risks to the Bulk Electric System from vendor products or services as specified in the requirement. Examples of processes, or outcomes of these processes, for complying with Part 1.1 are described below. A Responsible Entity could comply with Part 1.1 using either the first (team review) approach, or the second (risk assessment process) approach, a combination of the two approaches, or another approach determined by the Responsible Entity to comply with Part 1.1.

- A Responsible Entity can develop a process to form a team of subject matter experts from across the organization to participate in the BES Cyber System planning and acquisition process(es). The Responsible Entity should consider the relevant subject matter expertise necessary to meet the objective of Part 1.1 and include the appropriate representation of business operations, security architecture, information communications and technology, supply chain, compliance, and legal. Examples of factors that this team could consider in planning for the procurement of BES Cyber Systems as specified in Part 1.1 include:
  - Cyber security risk(s) to the BES that could be introduced by a vendor in new or planned modifications to BES Cyber Systems.
  - Vendor security processes and related procedures, including: system architecture, change control processes, remote access requirements, and security notification processes.
  - Periodic review processes that can be used with critical vendor(s) to review and assess any changes in vendor's security controls, product lifecycle management, supply chain, and roadmap to identify opportunities for continuous improvement.
  - Vendor use of third party (e.g., product/personnel certification processes) or independent review methods to verify product and/or service security practices.
  - Third-party security assessments or penetration testing provided by the vendors.
  - Vendor supply chain channels and plans to mitigate potential risks or disruptions.
  - Known system vulnerabilities; known threat techniques, tactics, and procedures; and related mitigation measures that could be introduced by vendor's information systems, components, or information system services.
  - Corporate governance and approval processes.
  - Methods to minimize network exposure, e.g., prevent internet accessibility, use of firewalls, and use of secure remote access techniques.
  - Methods to limit and/or control remote access from vendors to Responsible Entity's BES Cyber Systems.
  - Vendor's risk assessments and mitigation measures for cyber security during the planning and procurement process.
  - Mitigating controls that can be implemented by the Responsible Entity of the vendor. Examples include hardening the information system, minimizing the attack surface, ensuring ongoing support for system components, identification of alternate sources for critical components, etc.
- A Responsible Entity can develop a risk assessment process to identify and assess potential cyber security risks resulting from (i) procuring and installing vendor equipment and software and (ii) transitions from one vendor(s) to another vendor(s). This process could consider the following:
  - Potential risks based on the vendor's information systems, system components, and/or information system services / integrators. Examples of considerations include:

- Critical systems, components, or services that impact the operations or reliability of BES Cyber Systems.
- Product components that are not owned and managed by the vendor that may introduce additional risks, such as open source code or components from third party developers and manufacturers.

- Potential risks based on the vendor's risk management controls. Examples of vendor risk management controls to consider include[2]:
  - Personnel background and screening practices by vendors.
  - Training programs and assessments of vendor personnel on cyber security.
  - Formal vendor security programs which include their technical, organizational, and security management practices.
  - Vendor's physical and cyber security access controls to protect the facilities and product lifecycle.
  - Vendor's security engineering principles in (i) developing layered protections; (ii) establishing sound security policy, architecture, and controls as the foundation for design; (iii) incorporating security requirements into the system development lifecycle; (iv) delineating physical and logical security boundaries; (v) ensuring that system developers are training on how to build security software; (vi) tailoring security controls to meet organizational and operational needs; (vii) performing threat modeling to identify use cases, threat agents, attack vectors, and attack patterns as well as compensating controls and design patterns needed to mitigate risk; and (viii) reducing risk to acceptable levels, thus enabling informed risk management decisions. (NIST SP 800-53 SA-8 – Security Engineering Principles).
  - System Development Life Cycle program (SDLC) methodology from design through patch management to understand how cyber security is incorporated throughout the vendor's processes.
  - Vendor certifications and their alignment with recognized industry and regulatory controls.
  - Summary of any internal or independent cyber security testing performed on the vendor products to ensure secure and reliable operations.[3]
  - Vendor product roadmap describing vendor support of software patches, firmware updates, replacement parts and ongoing maintenance support.
  - Identify processes and controls for ongoing management of Responsible Entity and vendor's intellectual property ownership and responsibilities, if applicable. Examples include use of encryption algorithms for securing software code, data and information, designs, and proprietary processes while at rest or in transit.
- Based on risk assessment, identify mitigating controls that can be implemented by the Responsible Entity or the vendor. Examples include hardening the information system, minimizing the attack surface, ensuring ongoing support for system components, identification of alternate sources for critical components, etc.

[2] Tools such as the Standardized Information Gathering (SIG) Questionnaire from the Shared Assessments Program can aid in assessing vendor risk.

[3] For example, a Responsible Entity can request that the vendor provide a Standards for Attestation Engagements (SSAE) No. 18 SOC 2 audit report.

1.2. *One or more process(es) used in procuring BES Cyber Systems that address the following, as applicable:*

A Responsible Entity could document in its supply chain cyber security risk management plan one or more processes that it will use when procuring BES Cyber Systems to address Parts 1.2.1 through 1.2.6. The following are examples of processes, or outcomes of these processes, for complying with Part 1.2.

- Request cyber security terms relevant to applicable Parts 1.2.1 through 1.2.6 in the procurement process (request for proposal (RFP) or contract negotiation) for BES Cyber Systems to ensure that vendors understand the cyber security expectations for implementing proper security controls throughout the design, development, testing, manufacturing, delivery, installation, support, and disposition of the product lifecycle[4].
- During negotiations of procurement contracts or processes with vendors, the Responsible Entity can document the rationale, mitigating controls, or acceptance of deviations from the Responsible Entity's standard cyber security procurement language that is applicable to the vendor's system component, system integrators, or external service providers.

Examples of ways that a Responsible Entity could, through process(es) for procuring BES Cyber Systems required by Part 1.2, comply with Parts 1.2.1 through 1.2.6 are described below.

1.2.1. *Notification by the vendor of vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*

- In an RFP or during contract negotiations, request that the vendor include in the contract provisions an obligation for the vendor to provide notification of any identified, threatened, attempted or successful breach of vendor's components, software or systems (*e.g.,* "security event") that have potential adverse impacts to the availability or reliability of BES Cyber Systems. Security event notifications to the Responsible Entity should be sent to designated point of contact as determined by the Responsible Entity and vendor. Examples of information to request that vendor's include in notifications to the Responsible Entity are(i) mitigating controls that the Responsible Entity can implement, if applicable (ii) availability of patch or corrective components, if applicable.

1.2.2. *Coordination of responses to vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*

- A Responsible Entity and vendor can agree on service level agreements for response to cyber security incidents and commitment from vendor to collaborate with the Responsible Entity in implement mitigating controls and product corrections.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor such that, in the event the vendor identifies a vulnerability that has resulted

[4] An example set of baseline supply chain cyber security procurement language for use by BES owners, operators, and vendors during the procurement process can be obtained from the "Cybersecurity Procurement Language for Energy Delivery Systems" developed by the Energy Sector Control Systems Working Group (ESCSWG).

in a cyber security incident related to the products or services provided to the Responsible Entity, the vendor should provide notification to Responsible Entity. The contract could specify that the vendor provide defined information regarding the products or services at risk and appropriate precautions available to minimize risks. Until the cyber security incident has been corrected, the vendor could be requested to perform analysis of information available or obtainable, provide an action plan, provide ongoing status reports, mitigating controls, and final resolution within reasonable periods as agreed on by vendor and Responsible Entity.

1.2.3. *1.2.3. Notification by vendors when remote or onsite access should no longer be granted to vendor representatives;*

- In an RFP or during contract negotiations, request that the vendor include in the contract provisions an obligation for the vendor to provide notification to the Responsible Entity when vendor employee remote or onsite access should no longer be granted. This does not require the vendor to share sensitive information about vendor employees. Circumstances for no longer granting access to vendor employees include: (i) vendor determines that any of the persons permitted access is no longer required, (ii) persons permitted access are no longer qualified to maintain access, or (iii) vendor's employment of any of the persons permitted access is terminated for any reason. Request vendor cooperation in obtaining Responsible Entity notification within a negotiated period of time of such determination. The vendor and Responsible Entity should define alternative methods that will be implemented in order to continue ongoing operations or services as needed.
- If vendor utilizes third parties (or subcontractors) to perform services to Responsible Entity, require vendors to obtain Responsible Entity's prior approval and require third party's adherence to the requirements and access termination rights imposed on the vendor directly.

1.2.4. *Disclosure by vendors of known vulnerabilities;*

- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor for cooperation in obtaining access to summary documentation within a negotiated period of any identified security breaches involving the procured product or its supply chain that impact the availability or reliability of the Responsible Entity's BES Cyber System. Documentation should include a summary description of the breach, its potential security impact, its root cause, and recommended corrective actions involving the procured product.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor for cooperation in obtaining, within a negotiated time period after establishing appropriate confidentiality agreement, access to summary documentation of uncorrected security vulnerabilities in the procured product that have not been publicly disclosed. The summary documentation should include a description of each vulnerability and its potential impact, root cause, and recommended compensating security controls, mitigations, and/or procedural workarounds.
- During procurement, review with the vendor summary documentation of publicly disclosed vulnerabilities in the product being procured and the status of the vendor's disposition of those publicly disclosed vulnerabilities.

1.2.5. *Verification of software integrity and authenticity of all software and patches provided by the vendor for use in the BES Cyber System; and*

- During procurement, request access to vendor documentation detailing the vendor patch management program and update process for all system components being procured (including third-party hardware, software, and firmware). This documentation should include the vendor's method or recommendation for how the integrity of the patch is validated by Responsible Entity. Ask vendors to describe the processes they use for delivering software and the methods that can be used to verify the integrity and authenticity of the software upon receipt, including systems with preinstalled software.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor to provide access to vendor documentation for the procured products (including third-party hardware, software, firmware, and services) regarding the release schedule and availability of updates and patches that should be considered or applied. Documentation should include instructions for securely applying, validating and testing the updates and patches.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor to provide appropriate software and firmware updates to remediate newly discovered vulnerabilities or weaknesses within a reasonable period for duration of the product life cycle. Consideration regarding service level agreements for updates and patches to remediate critical vulnerabilities should be a shorter period than other updates. If updates cannot be made available by the vendor within a reasonable period, the vendor should be required to provide mitigations and/or workarounds.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor to provide fingerprints or cipher hashes for all software so that the Responsible Entity can verify the values prior to installation on the BES Cyber System to verify the integrity of the software.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor such that when third-party software components are provided by the vendor, the vendors provide appropriate updates and patches to remediate newly discovered vulnerabilities or weaknesses of the third-party software components.

1.2.6. *Coordination of controls for (i) vendor-initiated Interactive Remote Access, and (ii) system-to-system remote access with a vendor(s).*

- During procurement, request vendors specify specific IP addresses, ports, and minimum privileges required to perform remote access services.
- Request vendors use individual user accounts that can be configured to limit access and permissions.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor to maintain their IT assets (hardware, software and firmware) connecting to Responsible Entity network with current updates to remediate security vulnerabilities or weaknesses identified by the original OEM or Responsible Entity.
- During procurement, request vendors document their processes for restricting connections from unauthorized personnel. Vendor personnel are not authorized to disclose or share account credentials, passwords or established connections.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor such that for vendor system-to-system connections that may limit the Responsible Entity's capability to authenticate the personnel connecting from the vendor's systems, the vendor will maintain complete and accurate books, user logs, access credential data, records, and other information applicable to connection access activities for a negotiated time period.

Requirement R2

R2. *Each Responsible Entity shall implement its supply chain cyber security risk management plan(s) specified in Requirement R1.*

Note: Implementation of the plan does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the following issues are beyond the scope of Requirement R2: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.

General Considerations for R2

Implementation of the supply chain cyber security risk management plan(s) does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders), consistent with Order No. 829 (P. 36). Contracts entering the Responsible Entity's procurement process (e.g. through Request for Proposals) on or after the effective date are within scope of CIP-013-1. Contract effective date, commencement date, or other activation dates specified in the contract do not determine whether the contract is within scope of CIP-013-1.

Requirement R3

R3. *Each Responsible Entity shall review and obtain CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) specified in Requirement R1 at least once every 15 calendar months.*

General Considerations for R3

In the Requirement R3 review, responsible entities should consider new risks and available mitigation measures, which could come from a variety of sources that include NERC, DHS, and other sources.

Implementation Guidance for R3

Responsible entities use various processes to address this requirement. Below are some examples of approaches to comply with this requirement:

- A team of subject matter experts from across the organization representing appropriate business operations, security architecture, information communications and technology, supply chain, compliance, legal, etc. reviews the supply chain cyber security risk management plan at least once every 15 calendar months to reassess for any changes needed. Sources of information for changes include, but are not limited to:
  - Requirements or guidelines from regulatory agencies
  - Industry best practices and guidance that improve supply chain cyber security risk management controls (e.g. NERC, DOE, DHS, ICS-CERT, Canadian Cyber Incident Response Center (CCIRC), and NIST).
  - Mitigating controls to address new and emerging supply chain-related cyber security concerns and vulnerabilities
  - Internal organizational continuous improvement feedback regarding identified deficiencies, opportunities for improvement, and lessons learned.
- The CIP Senior Manager, or approved delegate, reviews any changes to the supply chain cyber security risk management plan at least once every 15 calendar months. Reviews may be more frequent based on the timing and scope of changes to the supply chain cyber security risk management plan(s). Upon approval of changes to the supply chain cyber security risk management plan(s), the CIP Senior Manager or approved delegate should provide appropriate communications to the affected organizations or individuals. Additionally, communications or training material may be developed to ensure any organizational areas affected by revisions are informed.

References

- Utilities Technology Council (UTC) “Cyber Supply Chain Risk management for Utilities – Roadmap for Implementation”
- ISO/IEC 27036 – Information Security in Supplier Relationships
- NIST SP 800-53 - Security and Privacy Controls for Federal Information Systems and Organizations System and Services Acquisition SA-3, SA-8 and SA-22
- NIST SP 800-161 - Supply Chain Risk Management Practices for Federal Information Systems and Organizations;
- Energy Sector Control Systems Working Group (ESCSWG) - “Cybersecurity Procurement Language for Energy Delivery Systems”

Order No. 829 Citation	Directive / Guidance	Resolution
P 43	[the Commission directs] that NERC, pursuant to section 215(d)(5) of the FPA, develop a forward-looking, objective-driven new or modified Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations.	Proposed CIP-013-1 addresses the directive. The purpose of the proposed standard is: *To mitigate cyber security risks to the reliable operation of the Bulk Electric System (BES) by implementing security controls for supply chain risk management of BES Cyber Systems.* CIP-013-1 is applicable to high and medium impact BES Cyber Systems. The proposed applicability appropriately focuses industry resources on supply chain cyber security risk management for industrial control system hardware, software, and computing and networking services associated with BES operations.
P 44	[the Commission directs] NERC to submit the new or modified Reliability Standard within one year of the effective date of this Final Rule. NERC should submit an informational filing [by December 26, 2016] with a plan to address the Commission's directive.	The proposed/modified standard(s) must be filed by September 27, 2017. NERC filed its plan to address the directive on December 15, 2016.
P 45	The plan required by the new or modified Reliability Standard developed by NERC should address, at a minimum, the following four specific security objectives in the context of addressing supply chain management risks: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls. Responsible entities should be required to achieve these four objectives but have the flexibility as to how to reach the objective (i.e., the Reliability Standard should set goals (the	The directive is addressed by Requirements R1, ~~R3~~R2, ~~R4,~~ and ~~R5~~ R3 of proposed CIP-013-1. Requirement R1 specifies that entities must ~~implement~~ develop, and Requirement R2 specifies that entities must implement, one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems that ~~address~~ include one or more

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	"what"), while allowing flexibility in how a responsible entity subject to the Reliability Standard achieves that goal (the "how")).	process(es)~~controls~~ for mitigating cyber security risks to BES Cyber Systems ~~and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets~~. The plans address the four objectives from Order No. 829 (P 45) during the planning, acquisition, and deployment phases of the system life cycle. ~~Requirements R3 through R5 address controls for software integrity and authenticity and vendor remote access that apply to the operate/maintain phase of the system life cycle as described further below.~~ **Proposed CIP-013-1 Requirement R1** **R1.** Each Responsible Entity shall ~~implement~~ develop one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems. ~~that address controls for mitigating cyber security risks to BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets.~~ The plan(s) shall ~~address~~include: ~~**1.1.**~~ One or more process(es) used in planning for the procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another

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		vendor(s)~~One or more process(es) used The use of controls in planning for the procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; (ii) network architecture security; and (iii) transitions from one vendor(s) to another vendor(s). planning and development to:~~ ~~**1.2.** Identify and assess risk(s) during the procurement and deployment of vendor products and services; and~~ ~~**1.3.**1.1. Evaluate methods to address identified risk(s).~~ ~~**1.4.**1.2. One or more process(es) used in procuring BES Cyber Systems ~~The use of controls in procuring vendor product(s) or service(s)~~ that address the following, as applicable ~~items, to the extent each item applies to the Responsible Entity's BES Cyber Systems and, if applicable, associated Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets~~: **1.2.1.** ~~Process(es) for n~~Notification by the ~~of~~ vendor of vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity~~events~~;

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		~~1.4.1.~~1.2.2. Coordination of responses to vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity; ~~1.4.2.~~1.2.3. ~~Process(es) for n~~Notification by vendors when ~~vendor employee~~ remote or onsite access should no longer be granted to vendor representatives; ~~1.4.3.~~1.2.4. ~~Process(es) for d~~Disclosure by vendors of known vulnerabilities; ~~1.4.4. Coordination of response to vendor-related cyber security incidents;~~ ~~1.4.5.~~1.2.5. ~~Process(es) for verifying~~Verification of software integrity and authenticity of all software and patches provided by the vendor ~~that are intended~~ for use in the BES Cyber System; and ~~1.4.6.~~1.2.6. Coordination of ~~remote access~~ controls for (i) vendor-initiated Interactive Remote Access, and (ii) system-to-system remote access with a vendor(s)~~; and Other process(es) to address risk(s) as determined in Part 1.1.2, if applicable~~. **Proposed CIP-013-1 Requirement R2** **R2.** Each Responsible Entity shall implement its supply chain cyber security risk management plan(s) specified in Requirement R1.

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P 46	The new or modified Reliability Standard should also require a periodic reassessment of the utility's selected controls. Consistent with or similar to the requirement in Reliability Standard CIP-003-6, Requirement R1, the Reliability Standard should require the responsible entity's CIP Senior Manager to review and approve the controls adopted to meet the specific security objectives identified in the Reliability Standard at least every 15 months. This periodic assessment should better ensure that the required plan remains up-to-date, addressing current and emerging supply chain-related concerns and vulnerabilities.	The directive is addressed in proposed CIP-013-1 Requirement ~~R2~~R3. **Proposed CIP-013-1 Requirement ~~R2~~R3** **~~R2~~R3.** Each Responsible Entity shall review and obtain CIP Senior Manager or delegate approval of ~~update, as necessary,~~ its supply chain cyber security risk management plan(s) specified in Requirement R1 at least once every 15 calendar months~~, which shall include:~~ ~~**2.1.** Evaluation of revisions, if any, to address applicable new supply chain security risks and mitigation measures; and~~ ~~**2.2.** Obtaining CIP Senior Manager or delegate approval.~~
p 47	Also, consistent with this reliance on an objectives-based approach, and as part of this periodic review and approval, the responsible entity's CIP Senior Manager should consider any guidance issued by NERC, the U.S. Department of Homeland Security (DHS) or other relevant authorities for the planning, procurement, and operation of industrial control systems and supporting information systems equipment since the prior approval, and identify any changes made to address the recent guidance.	The directive is addressed in proposed CIP-013-1 Requirement ~~R2~~ R3 ~~part 2.1~~ (shown above) and supporting guidance. **Proposed CIP-013-1 Rationale for Requirement ~~R2~~R3:** ~~Order No. 829 also directs that the~~Entities perform periodic assessment ~~"ensure that the required~~to keep plans ~~remains~~ up-to-date and, addressing current and emerging supply chain-related concerns and vulnerabilities~~" (P. 47)~~. Examples of sources of information that the entity could consider~~s~~ include guidance or information issued by: •NERC or the E-ISAC •ICS-CERT •Canadian Cyber Incident Response Centre (CCIRC)

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		~~*Technical Guidance and Examples*~~*Implementation Guidance* ~~document~~ developed by the drafting team and submitted for ERO endorsement includes example controls.
Objective 1: Software Integrity and Authenticity		
P 48	The new or modified Reliability Standard must address verification of: (1) the identity of the software publisher for all software and patches that are intended for use on BES Cyber Systems; and (2) the integrity of the software and patches before they are installed in the BES Cyber System environment.	The directive is addressed in proposed CIP-013-1 Requirement R1 Part 1.2.5 (discussed above) and CIP-010-3 Requirements ~~R3~~ R1 ~~and R5~~ Part 1.6~~5.1~~. ~~CIP-013-1 Requirement R3 applies to high and medium impact BES Cyber Systems.~~ The objective of verifying software integrity and authenticity is to ensure that the software being installed in the BES Cyber System was not modified without the awareness of the software supplier and is not counterfeit. **Proposed CIP-~~013~~010-~~1~~ 3 Requirement ~~R3~~R1** **R1.** Each Responsible Entity shall implement one or more documented process(es) that collectively include each of the applicable requirement parts in *CIP-010-3 Table R1 – Configuration Change Management*.~~Each Responsible Entity shall implement one or more documented process(es) for verifying the integrity and authenticity of the following software and firmware before being placed in operation on high and medium impact BES Cyber Systems:~~ **1.6.** For a change that deviates from the existing baseline configuration associated with baseline items in Parts 1.1.1, 1.1.2, and 1.1.5, and when the method to do so is available to the Responsible Entity from the software source: **1.6.1.** Verify the identity of the software source; and

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		1.6.2. Verify the integrity of the software obtained from the software source.~~Operating System(s);~~ ~~**3.1.** Firmware;~~ ~~**3.2.** Commercially available or open-source application software; and~~ ~~**3.3.** Patches, updates, and upgrades to 3.1 through 3.3.~~ ~~**Proposed CIP-013-1 Requirement R5**~~ ~~**R5.** Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall have one or more documented cyber security policies, which shall be reviewed and approved by the CIP Senior Manager or delegate at least once every 15 calendar months, that address the following topics for its low impact BES Cyber Systems:~~ ~~**5.1.** Integrity and authenticity of software and firmware and any patches, updates, and upgrades to software and firmware; and...~~
Objective 2: Vendor Remote Access to BES Cyber Systems		
P 51	The new or modified Reliability Standard must address responsible entities' logging and controlling all third-party (i.e., vendor) initiated remote access sessions. This objective covers both user-initiated and machine-to-machine vendor remote access.	The directive is addressed by proposed CIP-~~013~~005-~~1~~6 Requirement ~~R4~~ R2 Parts ~~4.1~~2.4 and ~~4.2~~2.5. The objective is to mitigate potential risks of a compromise at a vendor during an active remote access session with a Responsible Entity from impacting the BES.~~ and Requirement R5 Part 5.2. Requirement R4 applies to high and medium impact BES Cyber Systems.~~

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		~~Requirement R5 applies to low impact BES Cyber Systems.~~ The objective of Requirement R2 Part 2.4 is for entities to have visibility of active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access) that are taking place on their system. The obligation in Part 2.4 requires entities to have a method to determine active vendor remote access sessions. The objective of Requirement R2 Part 2.5 is for entities to have the ability to rapidly disable active remote access sessions in the event of a system breach. **Proposed CIP-~~013~~005-~~1~~ 6 Requirement ~~R4~~R2** **R2.** Each Responsible Entity shall implement one or more documented processes that collectively include the applicable requirement parts, where technically feasible, in CIP-005-6 Table R2 –Remote Access Management.~~Each Responsible Entity shall implement one or more documented process(es) for controlling vendor remote access to high and medium impact BES Cyber Systems. The process(es) shall provide the following for (i) vendor-initiated Interactive Remote Access and (ii) system-to-system remote access with a vendor(s)~~: ~~**4.1.** Authorization of remote access by the Responsible Entity;~~ ~~**4.2.** Logging and monitoring of remote access sessions to detect unauthorized activity; and~~ ~~**4.3.** Disabling or otherwise responding to unauthorized activity during remote access sessions.~~

Order No. 829 Citation	Directive / Guidance	Resolution
		2.4 Have one or more methods for determining active vendor remote access sessions (including Interactive Remote Access and system-to-system remote access). **2.5** Have one or more method(s) to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access). ~~**Proposed CIP-013-1 Requirement R5**~~ ~~**R5.** Each Responsible Entity with at least one asset identified in CIP-002 containing low impact BES Cyber Systems shall have one or more documented cyber security policies, which shall be reviewed and approved by the CIP Senior Manager or delegate at least once every 15 calendar months, that address the following topics for its low impact BES Cyber Systems:~~ ~~**5.2.** Controlling vendor-initiated remote access, including system-to-system remote access with vendor(s).~~
P 52	In addition, controls adopted under this objective should give responsible entities the ability to rapidly disable remote access sessions in the event of a system breach.	The directive is addressed by CIP-005-6 Requirement ~~R4~~ R2 Part ~~4~~2.~~3~~ 45 (above) ~~and Requirement R5 Part 5.2 (above)~~.
Objective 3: Information System Planning and Procurement		
P 56	As part of this objective, the new or modified Reliability Standard must address a responsible entity's CIP Senior Manager's (or delegate's) identification and documentation of the risks of proposed information system planning and system	The directive is addressed in proposed CIP-013-1 Requirement R1 Part 1.1 (shown above).

Order No. 829 Citation	Directive / Guidance	Resolution
	development actions. This objective is intended to ensure adequate consideration of these risks, as well as the available options for hardening the responsible entity's information system and minimizing the attack surface.	
Objective 4: Vendor Risk Management and Procurement Controls		
P 59	The new or modified Reliability Standard must address the provision and verification of relevant security concepts in future contracts for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations. Specifically, NERC must address controls for the following topics: (1) vendor security event notification processes; (2) vendor personnel termination notification for employees with access to remote and onsite systems; (3) product/services vulnerability disclosures, such as accounts that are able to bypass authentication or the presence of hardcoded passwords; (4) coordinated incident response activities; and (5) other related aspects of procurement. NERC should also consider provisions to help responsible entities obtain necessary information from their vendors to minimize potential disruptions from vendor-related security events.	The directive is addressed in proposed CIP-013-1 Requirement R1 Part 1.2 (shown above).

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2016-03 Cyber Security Supply Chain Risk Management Reliability Standard ~~CIP-013-1~~

Applicable Standard(s)

CIP-005-6 — Cyber Security — Electronic Security Perimeters

CIP-010-3 — Configuration Change Management and Vulnerability Assessments

CIP-013-1 — Cyber Security — Supply Chain Risk Management

Requested Retirement(s)

CIP-005-5 — Cyber Security — Electronic Security Perimeters

CIP-010-2 — Configuration Change Management and Vulnerability Assessments~~None~~

Prerequisite Standard(s)

None

Applicable Entities

~~**CIP-013-1 — Cyber Security — Supply Chain Risk Management**~~

- Balancing Authority
- Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:
  - Each underfrequency Load shedding (UFLS) or undervoltage Load shedding (UVLS) system that:
  - Is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and
  - Performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.
  - Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.
  - Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.
- Generator Operator
- Generator Owner

- Reliability Coordinator
- Transmission Operator
- Transmission Owner

Background

On July 21, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 829 directing NERC to develop a new or modified Reliability Standard that addresses supply chain risk management for industrial control system hardware, software, and computing and networking services associated with Bulk Electric System (BES) operations. Order No. 829 (at P 2) states:

> "[The Commission directs] NERC to develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations. The new or modified Reliability Standard should address the following security objectives, [discussed in detail in the Order]: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls."

FERC directed NERC to submit the new or modified Reliability Standard(s) within one year of the effective date of Order No. 829, i.e., by September 27, 2017.

General Considerations

Consistent with the directive to develop a forward-looking Reliability Standard, the implementation of ~~r~~Reliability ~~s~~Standards in Project 2016-03 ~~CIP-013-1~~ do~~es~~ not require the abrogation or re-negotiation of contracts (including amendments to master agreements and purchase orders) with vendors, suppliers or other entities executed as of the effective date of the proposed Reliability ~~s~~Standards~~CIP-013-1~~ (See FERC Order No. 829, P. 36).

Contracts entering the Responsible Entity's procurement process (e.g. through Request for Proposals) on or after the effective date are within scope of CIP-013-1. Contract effective date, commencement date, or other activation dates specified in the contract do not determine whether the contract is within scope of CIP-013-1.

Effective Date

~~CIP-013-1 — Cyber Security — Supply Chain Risk Management~~For all Reliability ~~s~~Standards in Project 2016-03 — CIP-005-6, CIP-010-3, and CIP-013-1

Where approval by an applicable governmental authority is required, the Reliability ~~standards~~ Standards ~~s~~ shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~18~~)~~ months after the effective date of the applicable governmental authority's order approving the

Reliability ~~standards~~Standards~~s~~, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the Reliability ~~standards~~ Standards~~s~~ shall become effective on the first day of the first calendar quarter that is ~~twelve (12~~18~~)~~ months after the date the Reliability ~~standards~~ Standards~~s~~ is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Initial Performance of Periodic Requirements

CIP-013-1 Requirement ~~R2~~R3

The initial review and approval ~~and update, as necessary,~~ of supply chain cyber security risk management plans by CIP Senior Manager or Delegate pursuant to Requirement ~~R2~~ R3 must be completed on or before ~~within fifteen (15) calendar months of~~ the effective date of CIP-013-1.

Definition

None

Retirement Date

Standards listed in the **Requested Retirement(s)** section shall be retired immediately prior to the effective date in the particular jurisdiction in which the revised standards are becoming effective.~~None~~

Violation Risk Factor and Violation Severity Level Justifications

Project 2016-03 — Cyber Security — Supply Chain Risk Management

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in **Project 2016-03 — Cyber Security — Supply Chain Risk Management.** 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 by the ERO Sanctions Guidelines. The Cyber Security Supply Chain Standard Drafting Team applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSLs for the requirements under this project:

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. A planning requirement that is administrative in nature.

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-013-01, R1	
Proposed VRF	**Medium**
NERC VRF Discussion	R1 is a requirement in an Operations Planning time ~~frame~~ horizon to develop one or more documented supply chain cyber security risk management plan(s). If violated, it 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 the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.

VRF Justifications for CIP-013-01, R1	
Proposed VRF	**Medium**
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a new requirement addressing specific reliability goals.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Medium is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R1 contains only one objective, which is to address an entity's controls for managing cyber security risks to BES Cyber Systems during the planning, acquisition, and deployment phases of the system life cycle~~develop one or more documented supply chain cyber security risk management plan(s)~~. Since the requirement has only one objective, only one VRF was assigned.

VSLs for CIP-013-1, R1			
Lower	Moderate	High	Severe

The Responsible Entity developed one or more documented supply chain cyber security risk management plan(s) which include the use of processes in planning for procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the BES as specified in Part 1.1, and include the use of process(es) for procuring BES Cyber systems as specified in Part 1.2, but the plans do not include one of the elements in Part 1.2.1 through Part 1.2.6.~~N/A~~	The Responsible Entity developed one or more documented supply chain cyber security risk management plan(s) which include the use of processes in planning for procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the BES as specified in Part 1.1, and include the use of process(es) for procuring BES Cyber systems as specified in Part 1.2, but the plans do not include two or more of the elements in Part 1.2.1 through Part 1.2.6.~~N/A~~	The Responsible Entity developed one or more documented supply chain cyber security risk management plan(s), but the plan(s) did not include the use of processes in planning for procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the BES as specified in Part 1.1, or the plan(s) did not include the use of process(es) for procuring BES Cyber systems as specified in Part 1.2.~~The Responsible Entity implemented one or more documented supply chain risk management plan(s), but the plan(s) did not include one of the elements specified in Parts 1.1 or 1.2.~~	The Responsible Entity developed one or more documented supply chain cyber security risk management plan(s), but the plan(s) did not include the use of processes in planning for procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the BES as specified in Part 1.1, and the plan(s) did not include the use of process(es) for procuring BES Cyber systems as specified in Part 1.2. OR The Responsible Entity did not develop ~~The Responsible Entity did not implement~~one or more documented supply chain cyber security risk management plan(s) as specified in the Requirement.~~The Responsible Entity implemented one or more documented supply chain risk management plan(s), but the plan(s) did not include either of the elements specified in Parts 1.1 or 1.2.;~~ ~~OR~~ ~~The Responsible Entity did not implement one or more~~

			~~documented supply chain risk management plan(s) as specified in the Requirement.~~

VRF Justifications for CIP-013-1, R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 VSL assignment is for R1 is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VRF Justifications for CIP-013-1, R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that 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	Proposed VSLs are based on a single violation and not a cumulative violation methodology. The VSL is assigned for a single instance of failing to develop one or more documented supply chain cyber security risk management plan(s) that set forth the controls.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	An entity's violation of a single part of the plan specified in the requirement does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

VRF Justifications for CIP-013-1, R2	
Proposed VRF	**Medium**
NERC VRF Discussion	R2 is a requirement in Operations Planning time ~~frame~~ horizon that requires entities to implement its supply chain cybersecurity risk management plan(s) specified in Requirement R1. If violated, failing to implement this plan 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 the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a new requirement addressing specific reliability goals.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Medium is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** R2 contains only one objective and only one VRF was assigned. The requirement does not comingle more than one obligation.

VSLs for CIP-013-1, R2			
Lower	**Moderate**	**High**	**Severe**
~~The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 15 calendar months but less than or equal to 16 calendar months since the previous review as specified in the Requirement.~~N/A	~~The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 16 calendar months but less than or equal to 17 calendar months since the previous review as specified in the Requirement.~~N/A	~~The Responsible Entity reviewed and updated, as necessary, its supply chain cyber security risk management plan(s) and obtained CIP Senior Manager or delegate approval but did so more than 17 calendar months but less than or equal to 18 calendar months since the previous review as specified in the Requirement.~~N/A	The Responsible Entity did not implement its supply chain cyber security risk management plan(s) as specified in the requirement.~~The Responsible Entity did not review and update, as necessary, its supply chain cyber security risk management plan(s) and obtain CIP Senior Manager or delegate approval within 18 calendar months of the previous review as specified in the Requirement.~~

VSL Justifications for CIP-013-1, R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 VSL assignment for R2 is SEVERE which is consistent with ~~not~~ binary criteria. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for CIP-013-1, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that 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	Proposed VSL~~s are~~ is based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	~~An entity's violation of a single part of the requirement does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.~~ A single VSL of Severe is assigned.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

VRF Justifications for CIP-013-1, R3	
Proposed VRF	**Medium**
NERC VRF Discussion	R3 is a requirement in Operations Planning time ~~frame~~ horizon that requires the Responsible Entity to ~~perform~~ periodically review and obtain CIP Senior Manager or delegate approval of supply chain cyber security risk management plans. ~~implement one or more documented process(es) for software integrity and authenticity controls to address risks from compromised software and firmware on high and medium impact BES Cyber Systems.~~ The reliability objective is to ensure plans remain up to date and address current and emerging supply chain-related cyber security concerns and vulnerabilities. If the requirement is violated, it 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 the~~the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a new requirement addressing specific reliability goals.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Medium is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation**

VRF Justifications for CIP-013-1, R3	
Proposed VRF	**Medium**
	R3 contains only one objective and only one VRF was assigned. The requirement does not comingle more than one obligation.

VSLs for CIP-013-1, R3			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity reviewed and obtained CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) but did so more than 15 calendar months but less than or equal to 16 calendar months since the previous review as specified in the Requirement.~~N/A~~	The Responsible Entity reviewed and obtained CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) but did so more than 16 calendar months but less than or equal to 17 calendar months since the previous review as specified in the Requirement.~~N/A~~	The Responsible Entity reviewed and obtained CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) but did so more than 17 calendar months but less than or equal to 18 calendar months since the previous review as specified in the Requirement.~~N/A~~	The Responsible Entity did not review and obtain CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) within 18 calendar months of the previous review as specified in the Requirement.~~The Responsible Entity did not implement one or more documented process(es) for verifying the integrity and authenticity of software and firmware before being placed in operation on high and medium impact BES Cyber Systems as specified in the Requirement.~~

VSL Justifications for CIP-013-1, R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 VSL assignment is for R1 is not binary. ~~The VSL assignment for R4 is Severe which is consistent with binary criteria.~~ Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for CIP-013-1, R3	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that 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	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	An entity's violation of the review requirement by some number of months less than 18 calendar months does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.~~Only a Severe VSL is assigned.~~
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

VRF Justifications for CIP-~~013~~005-~~01~~06, ~~R4~~R2	
Proposed VRF	**Medium**
NERC VRF Discussion	~~R4~~ R2 is a requirement in an Operations Planning and Same Day Operations time ~~frame~~ horizon to implement one or more documented process~~(es)~~es for controlling vendor remote access to high and medium impact BES Cyber Systems. If violated, it 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~~ the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a ~~new~~ revised requirement with the addition of two parts addressing specific reliability goals. The VRF of Medium is consistent with the approved version of the standard.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of Medium is consistent with the NERC VRF definition as discussed above.
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** ~~R4~~ R2 contains only one objective and only one VRF was assigned. The requirement does not comingle more than one obligation.

VSLs for CIP-~~013~~005-~~1~~6, ~~R4~~R2			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity does not have documented processes for one or more of the applicable items for Requirement Parts 2.1 through 2.3.~~N/A~~	The Responsible Entity did not implement~~ed one or more documented~~ process~~(es)~~es for one of the applicable items for Requirement Parts 2.1 through 2.3~~controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include one of the elements specified in Part 4.1 through Part 4.3~~.	The Responsible Entity did not implement~~ed one or more documented~~ process~~(es)~~es for two of the applicable items for Requirement Parts 2.1 through 2.3~~controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include two of the elements specified in Part 4.1 through Part 4.3~~.	The Responsible Entity did not implement~~ed one or more documented~~ process~~(es)~~es for three of the applicable items for Requirement Parts 2.1 through 2.3; ~~controlling vendor remote access to high and medium impact BES Cyber Systems, but did not include any of the elements specified in Part 4.1 through Part 4.3;~~ OR The Responsible Entity did not have~~implement~~ one or more ~~documented process(es)~~methods for determining active ~~controlling~~ vendor remote access sessions (including Interactive Remote Access and system-to-system remote access) (2.4) ~~to high and medium impact BES Cyber Systems as specified in the Requirement~~and one or more methods to disable active vendor remote access (including Interactive Remote Access and system-to-system remote access) (2.5).

VSL Justifications for CIP-~~013005~~-~~16~~, ~~R4~~R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 VSL assignment for ~~R4~~ R2 is not binary. Guideline 2b: The proposed VSLs do not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for CIP-~~013005~~-~~16~~, ~~R4~~R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	An entity's violation of a single part of the requirement does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

VRF Justifications for CIP-~~013~~010-1, ~~R5~~R1	
Proposed VRF	~~Lower~~Medium
NERC VRF Discussion	~~R5~~ R1 is a requirement in Operations Planning time ~~frame~~ horizon that requires the Responsible Entity to implement one or more documented processes that include each of the applicable requirement parts for configuration change management. ~~with at least one asset identified in CIP-002 containing low impact BES Cyber Systems to have one or more documented cyber security policies to address software integrity and authenticity and vendor remote access for its low impact BES Cyber Systems. If violated, it would not, under the emergency, abnormal, or restorative conditions anticipated by the policies, 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.~~ If violated, it 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 the requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures.
FERC VRF G1 Discussion	**Guideline 1- Consistency w/ Blackout Report** This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	**Guideline 2- Consistency within a Reliability Standard** The requirement has no sub-requirements and is assigned a single VRF.
FERC VRF G3 Discussion	**Guideline 3- Consistency among Reliability Standards** This is a ~~new~~ revised requirement with an additional part to address~~ing~~ specific reliability goals. The VRF of Medium is consistent with the approved version of the standard.
FERC VRF G4 Discussion	**Guideline 4- Consistency with NERC Definitions of VRFs** A VRF of ~~Lower~~ Medium is consistent with the NERC VRF definition as discussed above.

VRF Justifications for CIP-~~013~~010-1, ~~R5~~R1	
Proposed VRF	~~Lower~~Medium
FERC VRF G5 Discussion	**Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation** ~~R5~~ R1 contains only one objective and only one VRF was assigned. The requirement does not comingle more than one obligation

VSLs for CIP-~~013~~010-~~1~~3, ~~R5~~R1			
Lower	**Moderate**	**High**	**Severe**
The Responsible Entity ~~had~~ has documented and implemented a configuration change management process(es) that includes only four of the required baseline items listed in 1.1.1 through 1.1.5. (1.1) ~~cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 15 calendar months but less than or equal to 16 calendar months from the previous review~~.	The Responsible Entity ~~had~~ has documented and implemented a configuration change management process(es) that includes only three of the required baseline items listed in 1.1.1 through 1.1.5. (1.1) ~~cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 16 calendar months but less than or equal to 17 calendar months from the previous review~~.	The Responsible Entity ~~had~~ has documented and implemented a configuration change management process(es) that includes only two of the required baseline items listed in 1.1.1 through 1.1.5. (1.1) ~~cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the cyber security policies but did not include one of the elements in Parts 5.1 or 5.2~~; OR The Responsible Entity ~~had~~ has The Responsible Entity has a	The Responsible Entity ~~had~~ has not documented or implemented any configuration change management process(es) (R1); ~~cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the cyber security policies but did not include either of the elements in Parts 5.1 or 5.2~~; OR The Responsible Entity ~~had~~ has documented and implemented a configuration change

		process to verify the identity of the software source (1.6.1) but does not have a process to verify the integrity of the software provided by the software source when the method to do so is available to the Responsible Entity from the software source (1.6.2).~~cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 17 calendar months but less than or equal to 18 calendar months from the previous review.~~	management process(es) that includes only one of the required baseline items listed in 1.1.1 through 1.1.5. (1.1); ~~cyber security policies specified in the requirement that were reviewed and approved by the CIP Senior Manager or delegate, however the approval was more than 15 calendar months but less than or equal to 16 calendar months from the previous review~~. OR The Responsible Entity does not have a process(es) that requires authorization and documentation of changes that deviate from the existing baseline configuration (1.2); OR The Responsible Entity does not have a process(es) to update baseline configurations within 30 calendar days of completing a change(s) that deviates from the existing baseline configuration (1.3); OR

			The Responsible Entity does not have a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration (1.4.1); OR The Responsible Entity has a process(es) to determine required security controls in CIP-005 and CIP-007 that could be impacted by a change(s) that deviates from the existing baseline configuration but did not verify and document that the required controls were not adversely affected following the change (1.4.2 & 1.4.3); OR The Responsible Entity does not have a process for testing changes in an environment that models the baseline configuration prior to implementing a change that deviates from baseline configuration (1.5.1); OR

			The Responsible Entity does not have a process to document the test results and, if using a test environment, document the differences between the test and production environments (1.5.2); OR The Responsible Entity does not have a process to verify the identity of the software source and the integrity of the software provided by the software source when the method to do so is available to the Responsible Entity from the software source (1.6).

VSL Justifications for CIP-~~013~~010-~~1~~3, ~~R5~~R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	There is no prior compliance obligation related to the subject of this standard.
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 VSL assignment for ~~R5~~ R1 is not binary. Guideline 2b: The proposed VSL does not use ambiguous terms, supporting uniformity and consistency in the determination of similar penalties for similar violations.

VSL Justifications for CIP-~~013~~010-~~1~~3, ~~R5~~R1	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses similar terminology to that 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	Proposed VSLs are based on a single violation and not a cumulative violation methodology.
FERC VSL G5 Requirements where a single lapse in protection can compromise computer network security, i.e., the 'weakest link' characteristic, should apply binary VSLs	An entity's violation of a single part of the requirement does not constitute a lapse in protection that compromises network security. Therefore a binary VSL is not warranted.
FERC VSL G6 VSLs for cyber security requirements containing interdependent tasks of documentation and implementation should account for their interdependence	There is no documentation and implementation interdependence within the requirement.

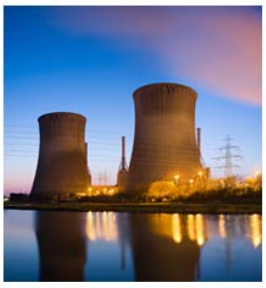
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

DRAFT

Cyber Security Supply Chain Risk Management Plans

Implementation Guidance for CIP-013-1

RELIABILITY | ACCOUNTABILITY



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Introduction

On July 21, 2016, the Federal Energy Regulatory Commission (FERC) issued Order No. 829 directing the North American Electric Reliability Corporation (NERC) to develop a new or modified Reliability Standard that addresses cyber security supply chain risk management for industrial control system hardware, software, and computing and networking services associated with Bulk Electric System (BES) operations as follows:

> [The Commission directs] NERC to develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations. The new or modified Reliability Standard should address the following security objectives, [discussed in detail in the Order]: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls.

Reliability Standard **CIP-013-1 – Cyber Security – Supply Chain Risk Management** addresses the relevant cyber security supply chain risks in the planning, acquisition, and deployment phases of the system life cycle for high and medium impact BES Cyber Systems[1].

This implementation guidance provides considerations for implementing the requirements in CIP-013-1 and examples of approaches that responsible entities could use to meet the requirements. The examples do not constitute the only approach to complying with CIP-013-1. Responsible Entities may choose alternative approaches that better fit their situation.

[1] Responsible Entities identify high and medium impact BES Cyber Systems according to the identification and categorization process required by CIP-002-5, or subsequent version of that standard.

Requirement R1

R1. *Each Responsible Entity shall develop one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems. The plan(s) shall include:*

1.1. *One or more process(es) used in planning for the procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another vendor(s).*

1.2. *One or more process(es) used in procuring BES Cyber Systems that address the following, as applicable:*

1.2.1. *Notification by the vendor of vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*

1.2.2. *Coordination of responses to vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*

1.2.3. *Notification by vendors when remote or onsite access should no longer be granted to vendor representatives;*

1.2.4. *Disclosure by vendors of known vulnerabilities;*

1.2.5. *Verification of software integrity and authenticity of all software and patches provided by the vendor for use in the BES Cyber System; and*

1.2.6. *Coordination of controls for (i) vendor-initiated Interactive Remote Access, and (ii) system-to-system remote access with a vendor(s).*

General Considerations for R1

The following are some general considerations for Responsible Entities as they implement Requirement R1:

First, in developing their supply chain cyber security risk management plan(s), Responsible entities should consider how to leverage the various components and phases of their processes (e.g. defined requirements, request for proposal, bid evaluation, external vendor assessment tools and data, third party certifications and audit reports, etc.) to help them meet the objective of Requirement R1 and give them flexibility to negotiate contracts with vendors to efficiently mitigate risks. Focusing solely on the negotiation of specific contract terms could have unintended consequences, including significant and unexpected cost increases for the product or service or vendors refusing to enter into contracts.

Additionally, a Responsible Entity may not have the ability to obtain each of its desired cyber security controls in its contract with each of its vendors. Factors such as competition, limited supply sources, expense, criticality of the product or service, and maturity of the vendor or product line could affect the terms and conditions ultimately negotiated by the parties and included in a contract. This variation in contract terms is anticipated and, in turn, the note in Requirement R2 provides that the actual terms and conditions of the contract are outside the scope of Reliability Standard CIP-013-1.

Note: Implementation of the plan does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the

following issues are beyond the scope of Requirement R2: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.

The focus of Requirement R1 is on the steps the Responsibility Entity takes to consider cyber security risks from vendor products or services during BES Cyber System planning and procurement. In the event the vendor is unwilling to engage in the negotiation process for cyber security controls, the Responsible Entity could explore other sources of supply or mitigating controls to reduce the risk to the BES cyber systems, as the Responsible Entity's circumstances allow.

In developing and implementing its supply chain cyber security risk management plan, a Responsible Entity may consider identifying and prioritizing security controls based on the cyber security risks presented by the vendor and the criticality of the product or service to reliable operations. For instance, Responsible Entities may establish a baseline set of controls for given products or services that a vendor must meet prior to transacting with that vendor for those products and services (i.e., "must-have controls"). As risks differ between products and services, the baseline security controls – or "must haves" – may differ for the various products and services the Responsible Entities procures for its BES Cyber Systems. This risk-based approach could help create efficiencies in the Responsible Entity's procurement processes while meeting the security objectives of Requirement R1.

The objective of addressing the verification of software integrity and authenticity during the procurement phase of BES Cyber System(s) (Part 1.2.5) is to identify the capability of the vendor(s) to ensure that the software installed on BES Cyber System(s) is trustworthy. Part 1.2.5 is not an operational requirement for Responsible Entities to perform the verification; instead, Part 1.2.5 is aimed at identifying during the procurement phase the vendor's capability to provide software integrity and authenticity assurance and establish vendor performance based on the vendor's capability in order to implement CIP-010-3, Requirement R1, Part 1.6.

Implementation Guidance for R1

Responsible entities use various processes as they plan to procure BES Cyber Systems. Below are some examples of approaches to comply with this requirement:

R1. *Each Responsible Entity shall develop one or more documented supply chain cyber security risk management plan(s) for high and medium impact BES Cyber Systems. The plan(s) shall include:*

- The Responsible Entity could establish one or more documents explaining the process by which the Responsible Entity will address supply chain cyber security risk management for high and medium impact BES Cyber Systems. To achieve the flexibility needed for supply chain cyber security risk management, Responsible Entities can use a "risk-based approach". One element of, or approach to, a risk-based cyber security risk management plan is **system-based**, focusing on specific controls for high and medium impact BES Cyber Systems to address the risks presented in procuring those systems or services for those systems. A risk-based approach could also be **vendor-based**, focusing on the risks posed by various vendors of its BES Cyber Systems. Entities may combine both of these approaches into their plans. This flexibility is important to account for the varying "needs and characteristics of responsible entities and the diversity of BES Cyber System environments, technologies, and risk (FERC Order No. 829 P 44)."

1.1. *One or more process(es) used in planning for the procurement of BES Cyber Systems to identify and assess cyber security risk(s) to the Bulk Electric System from vendor products or services resulting from: (i) procuring and installing vendor equipment and software; and (ii) transitions from one vendor(s) to another vendor(s).*

A Responsible Entity could document in its supply chain cyber security risk management plan one or more processes that it will use when planning for the procurement of BES Cyber Systems to identify and assess cyber security risks to the Bulk Electric System from vendor products or services as specified in the requirement. Examples of processes, or outcomes of these processes, for complying with Part 1.1 are described below. A Responsible Entity could comply with Part 1.1 using either the first (team review) approach, or the second (risk assessment process) approach, a combination of the two approaches, or another approach determined by the Responsible Entity to comply with Part 1.1.

- A Responsible Entity can develop a process to form a team of subject matter experts from across the organization to participate in the BES Cyber System planning and acquisition process(es). The Responsible Entity should consider the relevant subject matter expertise necessary to meet the objective of Part 1.1 and include the appropriate representation of business operations, security architecture, information communications and technology, supply chain, compliance, and legal. Examples of factors that this team could consider in planning for the procurement of BES Cyber Systems as specified in Part 1.1 include:
  - Cyber security risk(s) to the BES that could be introduced by a vendor in new or planned modifications to BES Cyber Systems.
  - Vendor security processes and related procedures, including: system architecture, change control processes, remote access requirements, and security notification processes.
  - Periodic review processes that can be used with critical vendor(s) to review and assess any changes in vendor's security controls, product lifecycle management, supply chain, and roadmap to identify opportunities for continuous improvement.
  - Vendor use of third party (e.g., product/personnel certification processes) or independent review methods to verify product and/or service security practices.
  - Third-party security assessments or penetration testing provided by the vendors.
  - Vendor supply chain channels and plans to mitigate potential risks or disruptions.
  - Known system vulnerabilities; known threat techniques, tactics, and procedures; and related mitigation measures that could be introduced by vendor's information systems, components, or information system services.
  - Corporate governance and approval processes.
  - Methods to minimize network exposure, e.g., prevent internet accessibility, use of firewalls, and use of secure remote access techniques.
  - Methods to limit and/or control remote access from vendors to Responsible Entity's BES Cyber Systems.
  - Vendor's risk assessments and mitigation measures for cyber security during the planning and procurement process.
  - Mitigating controls that can be implemented by the Responsible Entity of the vendor. Examples include hardening the information system, minimizing the attack surface, ensuring ongoing support for system components, identification of alternate sources for critical components, etc.
- A Responsible Entity can develop a risk assessment process to identify and assess potential cyber security risks resulting from (i) procuring and installing vendor equipment and software and (ii) transitions from one vendor(s) to another vendor(s). This process could consider the following:
  - Potential risks based on the vendor's information systems, system components, and/or information system services / integrators. Examples of considerations include:

- Critical systems, components, or services that impact the operations or reliability of BES Cyber Systems.
- Product components that are not owned and managed by the vendor that may introduce additional risks, such as open source code or components from third party developers and manufacturers.

- Potential risks based on the vendor's risk management controls. Examples of vendor risk management controls to consider include[2]:
  - Personnel background and screening practices by vendors.
  - Training programs and assessments of vendor personnel on cyber security.
  - Formal vendor security programs which include their technical, organizational, and security management practices.
  - Vendor's physical and cyber security access controls to protect the facilities and product lifecycle.
  - Vendor's security engineering principles in (i) developing layered protections; (ii) establishing sound security policy, architecture, and controls as the foundation for design; (iii) incorporating security requirements into the system development lifecycle; (iv) delineating physical and logical security boundaries; (v) ensuring that system developers are training on how to build security software; (vi) tailoring security controls to meet organizational and operational needs; (vii) performing threat modeling to identify use cases, threat agents, attack vectors, and attack patterns as well as compensating controls and design patterns needed to mitigate risk; and (viii) reducing risk to acceptable levels, thus enabling informed risk management decisions. (NIST SP 800-53 SA-8 – Security Engineering Principles).
  - System Development Life Cycle program (SDLC) methodology from design through patch management to understand how cyber security is incorporated throughout the vendor's processes.
  - Vendor certifications and their alignment with recognized industry and regulatory controls.
  - Summary of any internal or independent cyber security testing performed on the vendor products to ensure secure and reliable operations.[3]
  - Vendor product roadmap describing vendor support of software patches, firmware updates, replacement parts and ongoing maintenance support.
  - Identify processes and controls for ongoing management of Responsible Entity and vendor's intellectual property ownership and responsibilities, if applicable. Examples include use of encryption algorithms for securing software code, data and information, designs, and proprietary processes while at rest or in transit.
- Based on risk assessment, identify mitigating controls that can be implemented by the Responsible Entity or the vendor. Examples include hardening the information system, minimizing the attack surface, ensuring ongoing support for system components, identification of alternate sources for critical components, etc.

[2] Tools such as the Standardized Information Gathering (SIG) Questionnaire from the Shared Assessments Program can aid in assessing vendor risk.

[3] For example, a Responsible Entity can request that the vendor provide a Standards for Attestation Engagements (SSAE) No. 18 SOC 2 audit report.

1.2. *One or more process(es) used in procuring BES Cyber Systems that address the following, as applicable:*

A Responsible Entity could document in its supply chain cyber security risk management plan one or more processes that it will use when procuring BES Cyber Systems to address Parts 1.2.1 through 1.2.6. The following are examples of processes, or outcomes of these processes, for complying with Part 1.2.

- Request cyber security terms relevant to applicable Parts 1.2.1 through 1.2.6 in the procurement process (request for proposal (RFP) or contract negotiation) for BES Cyber Systems to ensure that vendors understand the cyber security expectations for implementing proper security controls throughout the design, development, testing, manufacturing, delivery, installation, support, and disposition of the product lifecycle[4].
- During negotiations of procurement contracts or processes with vendors, the Responsible Entity can document the rationale, mitigating controls, or acceptance of deviations from the Responsible Entity's standard cyber security procurement language that is applicable to the vendor's system component, system integrators, or external service providers.

Examples of ways that a Responsible Entity could, through process(es) for procuring BES Cyber Systems required by Part 1.2, comply with Parts 1.2.1 through 1.2.6 are described below.

1.2.1. *Notification by the vendor of vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*

- In an RFP or during contract negotiations, request that the vendor include in the contract provisions an obligation for the vendor to provide notification of any identified, threatened, attempted or successful breach of vendor's components, software or systems (*e.g.,* "security event") that have potential adverse impacts to the availability or reliability of BES Cyber Systems. Security event notifications to the Responsible Entity should be sent to designated point of contact as determined by the Responsible Entity and vendor. Examples of information to request that vendor's include in notifications to the Responsible Entity are(i) mitigating controls that the Responsible Entity can implement, if applicable (ii) availability of patch or corrective components, if applicable.

1.2.2. *Coordination of responses to vendor-identified incidents related to the products or services provided to the Responsible Entity that pose cyber security risk to the Responsible Entity;*

- A Responsible Entity and vendor can agree on service level agreements for response to cyber security incidents and commitment from vendor to collaborate with the Responsible Entity in implement mitigating controls and product corrections.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor such that, in the event the vendor identifies a vulnerability that has resulted

[4] An example set of baseline supply chain cyber security procurement language for use by BES owners, operators, and vendors during the procurement process can be obtained from the "Cybersecurity Procurement Language for Energy Delivery Systems" developed by the Energy Sector Control Systems Working Group (ESCSWG).

in a cyber security incident related to the products or services provided to the Responsible Entity, the vendor should provide notification to Responsible Entity. The contract could specify that the vendor provide defined information regarding the products or services at risk and appropriate precautions available to minimize risks. Until the cyber security incident has been corrected, the vendor could be requested to perform analysis of information available or obtainable, provide an action plan, provide ongoing status reports, mitigating controls, and final resolution within reasonable periods as agreed on by vendor and Responsible Entity.

1.2.3. *1.2.3. Notification by vendors when remote or onsite access should no longer be granted to vendor representatives;*

- In an RFP or during contract negotiations, request that the vendor include in the contract provisions an obligation for the vendor to provide notification to the Responsible Entity when vendor employee remote or onsite access should no longer be granted. This does not require the vendor to share sensitive information about vendor employees. Circumstances for no longer granting access to vendor employees include: (i) vendor determines that any of the persons permitted access is no longer required, (ii) persons permitted access are no longer qualified to maintain access, or (iii) vendor's employment of any of the persons permitted access is terminated for any reason. Request vendor cooperation in obtaining Responsible Entity notification within a negotiated period of time of such determination. The vendor and Responsible Entity should define alternative methods that will be implemented in order to continue ongoing operations or services as needed.
- If vendor utilizes third parties (or subcontractors) to perform services to Responsible Entity, require vendors to obtain Responsible Entity's prior approval and require third party's adherence to the requirements and access termination rights imposed on the vendor directly.

1.2.4. *Disclosure by vendors of known vulnerabilities;*

- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor for cooperation in obtaining access to summary documentation within a negotiated period of any identified security breaches involving the procured product or its supply chain that impact the availability or reliability of the Responsible Entity's BES Cyber System. Documentation should include a summary description of the breach, its potential security impact, its root cause, and recommended corrective actions involving the procured product.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor for cooperation in obtaining, within a negotiated time period after establishing appropriate confidentiality agreement, access to summary documentation of uncorrected security vulnerabilities in the procured product that have not been publicly disclosed. The summary documentation should include a description of each vulnerability and its potential impact, root cause, and recommended compensating security controls, mitigations, and/or procedural workarounds.
- During procurement, review with the vendor summary documentation of publicly disclosed vulnerabilities in the product being procured and the status of the vendor's disposition of those publicly disclosed vulnerabilities.

1.2.5. *Verification of software integrity and authenticity of all software and patches provided by the vendor for use in the BES Cyber System; and*

- During procurement, request access to vendor documentation detailing the vendor patch management program and update process for all system components being procured (including third-party hardware, software, and firmware). This documentation should include the vendor's method or recommendation for how the integrity of the patch is validated by Responsible Entity. Ask vendors to describe the processes they use for delivering software and the methods that can be used to verify the integrity and authenticity of the software upon receipt, including systems with preinstalled software.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor to provide access to vendor documentation for the procured products (including third-party hardware, software, firmware, and services) regarding the release schedule and availability of updates and patches that should be considered or applied. Documentation should include instructions for securely applying, validating and testing the updates and patches.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor to provide appropriate software and firmware updates to remediate newly discovered vulnerabilities or weaknesses within a reasonable period for duration of the product life cycle. Consideration regarding service level agreements for updates and patches to remediate critical vulnerabilities should be a shorter period than other updates. If updates cannot be made available by the vendor within a reasonable period, the vendor should be required to provide mitigations and/or workarounds.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor to provide fingerprints or cipher hashes for all software so that the Responsible Entity can verify the values prior to installation on the BES Cyber System to verify the integrity of the software.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor such that when third-party software components are provided by the vendor, the vendors provide appropriate updates and patches to remediate newly discovered vulnerabilities or weaknesses of the third-party software components.

1.2.6. *Coordination of controls for (i) vendor-initiated Interactive Remote Access, and (ii) system-to-system remote access with a vendor(s).*

- During procurement, request vendors specify specific IP addresses, ports, and minimum privileges required to perform remote access services.
- Request vendors use individual user accounts that can be configured to limit access and permissions.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor to maintain their IT assets (hardware, software and firmware) connecting to Responsible Entity network with current updates to remediate security vulnerabilities or weaknesses identified by the original OEM or Responsible Entity.
- During procurement, request vendors document their processes for restricting connections from unauthorized personnel. Vendor personnel are not authorized to disclose or share account credentials, passwords or established connections.
- In an RFP or during contract negotiations, request that the vendor include in contract provisions a commitment from the vendor such that for vendor system-to-system connections that may limit the Responsible Entity's capability to authenticate the personnel connecting from the vendor's systems, the vendor will maintain complete and accurate books, user logs, access credential data, records, and other information applicable to connection access activities for a negotiated time period.

Requirement R2

R2. *Each Responsible Entity shall implement its supply chain cyber security risk management plan(s) specified in Requirement R1.*

Note: Implementation of the plan does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders). Additionally, the following issues are beyond the scope of Requirement R2: (1) the actual terms and conditions of a procurement contract; and (2) vendor performance and adherence to a contract.

General Considerations for R2

Implementation of the supply chain cyber security risk management plan(s) does not require the Responsible Entity to renegotiate or abrogate existing contracts (including amendments to master agreements and purchase orders), consistent with Order No. 829 (P. 36). Contracts entering the Responsible Entity's procurement process (e.g. through Request for Proposals) on or after the effective date are within scope of CIP-013-1. Contract effective date, commencement date, or other activation dates specified in the contract do not determine whether the contract is within scope of CIP-013-1.

Requirement R3

R3. *Each Responsible Entity shall review and obtain CIP Senior Manager or delegate approval of its supply chain cyber security risk management plan(s) specified in Requirement R1 at least once every 15 calendar months.*

General Considerations for R3

In the Requirement R3 review, responsible entities should consider new risks and available mitigation measures, which could come from a variety of sources that include NERC, DHS, and other sources.

Implementation Guidance for R3

Responsible entities use various processes to address this requirement. Below are some examples of approaches to comply with this requirement:

- A team of subject matter experts from across the organization representing appropriate business operations, security architecture, information communications and technology, supply chain, compliance, legal, etc. reviews the supply chain cyber security risk management plan at least once every 15 calendar months to reassess for any changes needed. Sources of information for changes include, but are not limited to:
  - Requirements or guidelines from regulatory agencies
  - Industry best practices and guidance that improve supply chain cyber security risk management controls (e.g. NERC, DOE, DHS, ICS-CERT, Canadian Cyber Incident Response Center (CCIRC), and NIST).
  - Mitigating controls to address new and emerging supply chain-related cyber security concerns and vulnerabilities
  - Internal organizational continuous improvement feedback regarding identified deficiencies, opportunities for improvement, and lessons learned.
- The CIP Senior Manager, or approved delegate, reviews any changes to the supply chain cyber security risk management plan at least once every 15 calendar months. Reviews may be more frequent based on the timing and scope of changes to the supply chain cyber security risk management plan(s). Upon approval of changes to the supply chain cyber security risk management plan(s), the CIP Senior Manager or approved delegate should provide appropriate communications to the affected organizations or individuals. Additionally, communications or training material may be developed to ensure any organizational areas affected by revisions are informed.

References

- Utilities Technology Council (UTC) “Cyber Supply Chain Risk management for Utilities – Roadmap for Implementation”
- ISO/IEC 27036 – Information Security in Supplier Relationships
- NIST SP 800-53 - Security and Privacy Controls for Federal Information Systems and Organizations System and Services Acquisition SA-3, SA-8 and SA-22
- NIST SP 800-161 - Supply Chain Risk Management Practices for Federal Information Systems and Organizations;
- Energy Sector Control Systems Working Group (ESCSWG) - “Cybersecurity Procurement Language for Energy Delivery Systems”

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Considerations for Transmission Owner (TO) Control Centers (TOCC) with Capability to Perform Transmission Operator (TOP) Obligations

Project 2016-02 Modifications to CIP Standards
March 14, 2017

Introduction

The "TOCC White Paper" provides background and technical considerations for potential approaches to modifying the applicability of North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) Reliability Standards as they relate to the protection of BES Cyber System(s) at Transmission Owner Control Centers performing the functional obligations of a Transmission Operator. The TOCC White Paper was drafted by the standard drafting team ("SDT") for NERC Project 2016-02 Modifications to CIP Standards (Project 2016-02) for stakeholder consideration and comment. The TOCC White Paper has not been approved or endorsed by NERC. The SDT is using the TOCC White Paper as a standard development tool to collect feedback on the basis for revisions to the CIP standards on this issue, if any.

As outlined in the applicable Standards Authorization Request (SAR), NERC Project 2016-02, addresses the Federal Energy Regulatory Commission (FERC or Commission) Order No. 822 directives and the issues captured in the Version 5 Transition Advisory Group's (V5TAG) *CIP V5 Issues for Standard Drafting Team Consideration* (V5TAG Transfer Document). The V5TAG, comprised of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry's implementation activities. In the Transfer Document, the V5TAG outlined the issues which it believed required further modification or clarification within the CIP Reliability Standards. The necessary modifications were believed to support effective implementation; critical infrastructure security improvements; and/or consistency in Compliance Monitoring and Enforcement outcomes.

Among other things, the V5TAG Transfer Document proposes that the CIP SDT address the applicability of the CIP Reliability Standards to BES Cyber System(s) for a TO Control Center performing the functional obligations of a TOP. As such, the SAR for Project 2016-02 lists the following issues for the Project 2016-02 SDT to address:

1. The applicability of requirements on a TO's Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the Bulk Electric System (BES);
2. The definition of Control Center; and

3. The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.

To address the issues listed, the SDT identified the following five areas for examination and discussion: (1) the TOCC responsibilities as they relate to TOP functions or tasks within the NERC registration processes; (2) the roles that entity impact analyses and risk assessments play, including the NERC proposed beta criteria; (3) understanding of the phrase "performing functional obligations;" (4) a technical discussion on the capability vs. authority and span of control of BES Cyber System(s) associated with TOCCs; and (5) consideration of potential solutions. Each of these areas is discussed in this TOCC White Paper.

The SDT is seeking stakeholder feedback on its assessment of the TOCC issue area through the associated informal comment form. In particular, the SDT seeks feedback on the potential solutions proposed in this TOCC White Paper as well as any suggestions for alternative solutions.

V5TAG Background

As described in the NERC Project 2016-02 Standards Drafting Team SAR encompassing the V5TAG transfer document issues, there were multiple readings of the language “used to perform the functional obligation of” in CIP-002-5.1a, Attachment 1, criterion 2.12 and recommendations for clarification of:

- The applicability of requirements on a TOCC that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
- The definition of Control Center.
- The language scope of “perform the functional obligations of” throughout the Attachment 1 criteria.

The V5TAG suggested that the Project 2016-02 SDT consider the following potential options or recommendations for resolution:

- Provide additional clarity or revisions to CIP-002-5.1a, Attachment 1. Specifically around Transmission Owner Control Centers performing the functional obligations of a Transmission Operator, in particular for entities with small or lower-risk Cyber Asset risks.
- Clarify applicability of requirements on a TOCC that perform the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES. Currently, CIP-002-5.1a indicates that any Control Center performing the actions noted above is to be considered as having BES Cyber Systems categorized as medium impact, if not already identified as high impact. There is no allowance for a low-risk entity performing TOP functions to identify their assets as containing only low impact BES Cyber Systems.
- Revise the definition of Control Center if additional clarity will improve consistency in implementation, compliance and enforcement, and determination of applicability.

The TOCC whitepaper is an effort to fully inform industry about this issue and the SDT needs feedback from all industry participants on the topics in the associated comment form.

Related Issues Not in Scope of SAR

As described in the Standards Processes Manual, a 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.

Early in the SDT research effort, discussions with stakeholders revealed a potentially significant connection between the TOCC issue and the ERO Registration processes. The SDT explored this path and captured the following information.

In 2014, NERC completed development of a Risk-Based Registration process, which FERC approved in 2015. During the development effort, NERC considered the concept of a registration *lite* for those entities that may perform functional obligations but have less reliability impacts to the BES. These concerns were not specific to a registered function but were entity-dependent having a relationship with the TOCC. The Risk-Based Registration process concluded and determined there was not a defensible position for a registration *lite* concept, but given the remaining concerns, the ERO established NERC-led review panels developed from the Risk-Based Registration process to assess and confirm an impact rating for TOCCs, should the question arise in the future.

The review panel can be utilized for concerns with registration as a TO or TOP if the entity believes the designation it carries to be inappropriate. Entities that may be impacted by a change in a neighboring or fellow registered entity have a chance to participate in the panel process. To be more direct in linkage, if an entity has concerns about applicability of functional performance or tasks – this would not be addressed in a family of standards – but in the tools and programs as defined in the NERC Rules of Procedure (ROP). These are the ordered processes for any type of exception, if you will, from adherence to the standards and requirements.

In discussions with impacted stakeholders, the SDT learned that some TOPs believe they are inappropriately registered as TOPs and, as a result, are disproportionately impacted by the CIP standards. This registration issue is outside the scope of Project 2016-02. The SDT notes, however, that entities may use existing mechanisms to potentially resolve these concerns.

NERC Project 2016-02 Background

On January 21, 2016, the Commission issued Order No. 822, Revised Critical Infrastructure Protection Reliability Standards, approving seven CIP Reliability Standards and new or modified definitions. On March 9, 2016, the NERC Standards Committee (SC) authorized the SAR to be posted for a 30-day informal comment period from March 23 – April 21, 2016. Based on the comments received, the SDT made minor revisions to the SAR which was posted for an additional 30-day informal comment period June 1-30, 2016. The SC accepted the SAR revisions on July 20, 2016.

The purpose of NERC Project 2016-02 is to increase reliability and security to the Bulk-Power System (BPS) by enhancing cyber protection of BPS facilities. To help accomplish this, the SDT will: (1) address the Commission directives contained in Order No. 822, and (2) consider the V5TAG issues identified in the V5TAG Transfer Document.

It is important to note that the V5TAG issues relate to the language developed by the Project 2008-06 Cyber Security Order 706 Standards Drafting Team (706 SDT) as directed in FERC Order No. 706. The NERC Board of Trustees adopted the stakeholder-approved CIP Version 5 standards and FERC approved the standards on January 18, 2006. The Project 2016-02 SDT must consider the V5TAG issues based on the language of FERC Order No. 706 and the intent of the 706 SDT with a subset of the language captured below.

> 280. The Commission has two concerns regarding the misuse of facilities, and clarifies those concerns here. First, Requirement R1.2.1 requires responsible entities to consider control centers and backup control centers as potential critical assets. In determining whether those control centers should be critical assets, we believe that responsible entities should examine the impact on reliability if the control centers are unavailable, due for example to power or communications failures, or denial of service attacks. Responsible entities should also examine the impact that misuse of those control centers could have on the electric facilities they control and what the combined impact of those electric facilities could be on the reliability of the Bulk-Power System. The Commission recognizes that, when these matters are taken into account, it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be identified as a critical asset.

FERC reiterated its position on April 19, 2012 in FERC Order No. 761 (the order approving "Version 4 Critical Infrastructure Protection Reliability Standards"):

> 57. The Commission recognizes the diverging views among commenters regarding the protection of control centers and control systems afforded under the Version 4 CIP Reliability Standards. In Order No. 706, we stated that "it is difficult to envision a scenario in which a reliability coordinator, transmission operator or transmission owner control center or backup control center would not properly be identified as a critical asset." The Commission maintains this view. However, as we observed in the NOPR, the percentage of control centers to be identified as Critical Assets under Version 4 is 74 percent, which is an improvement over the number currently identified under Version 3. Therefore, it is reasonable to approve Version 4 because it will ensure that more control centers are identified as Critical Assets than are identified under Version 3. However, we continue to expect comprehensive protection of all control centers and control systems as NERC works to comply with the requirements of Order No. 706.

NERC Proposed Beta Criteria

Prior to the SAR, NERC compliance staff participating in the V5TAG recognized that Control Centers covered by the referenced criterion may not all pose the same level of risk to the BES, which is a fundamental aspect of CIP-002-5.1a impact-based categories. To evaluate each Control Center's risk to the BES, NERC compliance staff developed beta criteria to identify Control Centers that contain medium impact BES Cyber Systems and evaluate the entity risk impact with consideration of a low impact category. The beta criteria are more fully described below.

The first beta criterion of the evaluation posed the following question: "Does the Transmission Owner's facility operate at least two geographically separate transmission facilities?" If the answer to this beta criterion was no, the TO's facility would be identified as an asset that contains low impact BES Cyber Systems. If the answer was yes, then the evaluation moved on to the next criterion.

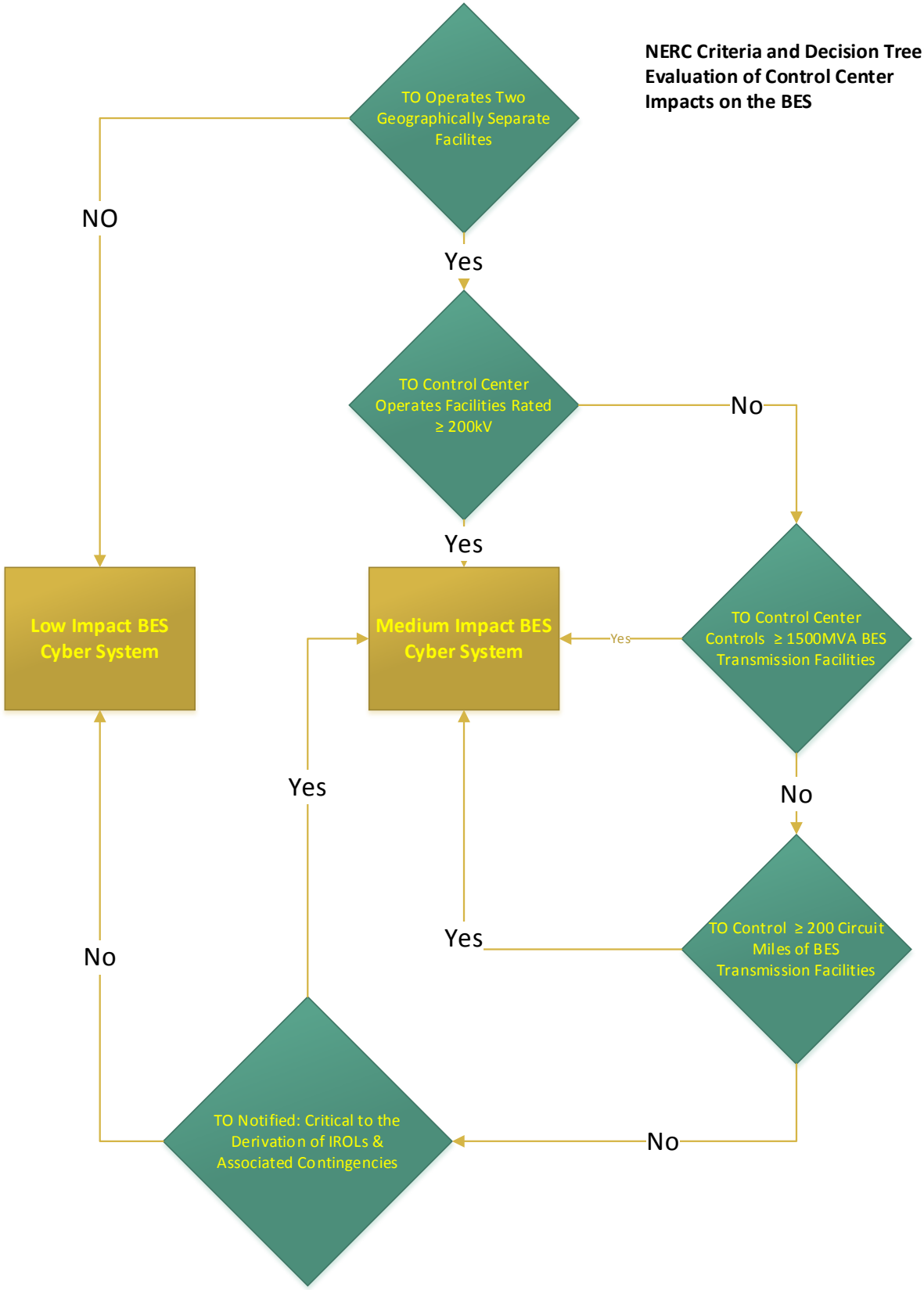
The second beta criterion consisted of the following question: "Do any of the Transmission Facilities operated by the Transmission Owner's Control Centers operate at or greater than 200 kV?" If the answer to this question was yes, then the evaluation resulted in the Control Center being identified as an asset that contained medium impact BES Cyber System(s). If the answer to this question was no then the evaluation proceeded to the next criterion.

The third beta criterion was labeled as the Group 1 criteria and consisted of three distinct questions:

1. "Does the Transmission Owner control 1500 MVA or more of Transmission capacity at BES Transmission Facilities controlled by the Transmission Owner's Control Centers?" It should be noted that this is not Transfer Capability through a Transmission Operator Area. Transmission capacity in this criterion was calculated by adding up the Facility ratings of all the Transmission Owner's BES Transmission Lines and capacitor banks. If the aggregated MVA value was greater than or equal to 1500 MVA, then the Control Center was identified as an asset that contains medium impact BES Cyber System(s). If the answer to this question was no, then the evaluation moved on to the next question.
2. "Does the Transmission Owner control more than 200 miles of Transmission?" This calculation was performed by adding up all of the circuit miles of the Transmission Owner's BES Transmission Facilities. If the answer to this question was yes, then the Control Center was identified as an asset that contained medium impact BES Cyber System(s). If the answer was no then the evaluation moved on to the final question.
3. "Has the Transmission Owner been notified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as having a Facility, controlled by the Transmission Owner's Control Centers that is critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies?" If the answer to this question was yes, then the Control Center was identified as an asset that contained medium impact BES Cyber System(s), if not it was treated as an asset that contains low impact BES Cyber System(s).

The SDT continues to evaluate the beta criteria as an option to pursue. In an effort to clarify the approach as captured, the following flowchart represents the consideration path for execution of the risk assessment.

NERC Criteria and Decision Tree: Evaluation of Control Center Impacts on the BES



Performing Functional Obligations

The SDT delved further into the intent behind the language: "performing the functional obligations of" and identified the following information associated with the creation of this language. The "performing functional obligation of" language was added in CIP-002-4 by the "Project 2008-6 Cyber Security Order Phase II" Standard Drafting Team. The CIP-002-4 Identifying Critical Cyber Assets guideline document references the "functional obligation" language in terms of a "formal delegation" from the registered entity:

http://www.nerc.com/pa/Stand/CIP0024RD/Project_2008-06_CIP-002-4_Guidance_clean_20101220.pdf

The "functional obligations" language first appears in a draft of CIP-002-4. The draft guidance associated with this first introduction of the language offered the following:

> Part 1.14 designates all control centers and control systems used to perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA) or Transmission Operator (TOP). EOP-008 requires that RCs, BAs and TOPs "ensure continued reliable operations of the Bulk Electric System (BES) in the event that a control center becomes inoperable." While it is clear that the primary and all backup control centers operated by RCs, BAs, and TOPs must be designated as Critical Assets, control systems at other applicable Responsible Entities that are used to perform the functional obligations of the RCs, BAs, or TOPs must also be designated as Critical Assets. These include control systems at Transmission Owners' control centers and backup control centers, for example, which have been formally delegated to perform some of these functions. Control systems were specifically called out separately from control centers to ensure that Entities fully evaluate those systems used to perform the functional obligations of the Reliability Coordinator, Balancing Authority, or Transmission Operator. These control systems may be located at a data center that is not co-located with the control center itself.

As discussed in summary meeting notes from the aforementioned SDT, the SDT commented on the designation of TOCC's as Critical Assets as follows:

> "As discussed in the Reference Document, this requirement is sourced from EOP-008. Control centers performing these functional obligations are considered important enough to require mandatory backup requirements and warrant designation as Critical Assets."

Given the information discussed above, the relationship to the operations and planning standards vary with different levels of potential impact. To perform functional tasks or obligations, a System Operator must either be certified as a Transmission Operator or Reliability Coordinator (RC) or take direction from a NERC-certified System Operator (Transmission Operator or RC). Maintaining a NERC certification can take significant investment of time and resources, so some System Operators that control BES Transmission Systems do not maintain certification and instead rely on only operating the System when directed by a NERC Certified System Operator. To address the scenario where an individual or entity is 1) performing BES Transmission operations, 2) is not a registered TOP and 3) equipment may have an impact on BES operations, the 706 SDT incorporated the language "used to perform the functional obligations of" to clarify that the equipment used by both NERC-certified System Operators and System Operators operated under the direction of a NERC-certified System Operator had to be protected and fully implement the security objective for protecting equipment used to perform TOP functions. The functional obligations of a TOP are identified in the NERC Rules of Procedure[1], with further examples included in the Functional

[1] http://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/NERC_ROP_Effective_20161031.pdf

Model and are also summarized in the BES Reliability Operating Services (BROS) in the Guidelines and Technical Basis of CIP-002-5.1a.

1) Capability versus Authority

In terms of CIP-002-5.1a and determination of risk level or impact classification, Attachment 1 criterion 2.12 focuses specifically on those Responsible Entities taking part in or performing both the Transmission Owner and/or the Transmission Operator reliability functions. As stated in the V5TAG Transfer Document, the language "used to perform the functional obligation of," was intended to "capture entities that perform obligations of a specific registered function, whether they are registered for that function or not." The statement inherently accommodates the risk that CIP-002-5.1a Attachment 1 is trying to mitigate. Regardless of how a Responsible Entity is registered, to adequately protect the BES, entities must look at not only the intended use but also the potential misuse of the BES Cyber System(s). If a malicious actor is capable of affecting the BES in a negative manner from a given BES Cyber System, that BES Cyber System needs to be protected accordingly to prevent such actions.

Regarding criterion 2.12, this notion calls into question whether it is appropriate to afford BES Cyber Systems protections based on authority to perform actions (registered functions) or capability to perform actions.

For criterion 2.12 in CIP-002-5.1a Attachment 1, it is clear that the intention is to require application of appropriate protections to BES Cyber Systems operated by Responsible Entities that fulfill TOP reliability functions, regardless of registration. An example of this would be a case where there are two Responsible Entities, one registered as a TO, and the other registered as a TOP. If the entity registered as the TO operates a Control Center and follows directives given by the TOP, the TO is clearly operating on behalf of the TOP. In this case, while the TO only does this when authorized by the TOP, the BES Cyber System(s) associated with the TO's Control Center possess the capability to be used by an unauthorized party to affect the BES, and must be protected as a BES Cyber Asset.

2) Span of Control

The TOP's span of control is not limited to just Transmission Lines, but to a large number of diverse Transmission Facilities that relate to the reliable operation of the BES. This complexity, together with the interrelated impact from the large number of diverse Functional Entity types that impact TOP functional obligations, makes it very difficult to define a justifiable threshold that can be rationalized considering all the scenarios that could impact Real-time operation for a TOCC.

CIP-002-5.1a, Attachment 1 categorizes BES Cyber Systems into risk based impact levels primarily based on the span of control of the BES Cyber System(s). The premise of this discussion is that the span of control for the TO and TOP functions should be more fully considered to determine whether a risk-basis exists for a low impact categorization for BES Cyber System(s) associated with Control Centers.

Evaluation of Potential Solutions

The SDT evaluated potential solutions (as recommended by V5TAG and others) against the facts and factors uncovered during the SDT research. The associated informal comment form includes questions for stakeholders that are intended to gather additional information and stakeholder positions related to these potential solutions.

1) Propose revisions to CIP-002-5.1a

If the SDT were to take action to respond to the TOCC issue, there are many variations of what may be an appropriate action. The following section proposes potential standard revision options.

a) Propose revisions to CIP-002-5.1a, Attachment 1, Criterion 2.12

The SDT considered the prospect of revising the Attachment 1, criterion 2.12 to add clarity for Responsible Entities. Criterion 2.12 establishes a medium impact level for "Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator not included in high impact rating (H), above." Under this option, the SDT would propose an impact rating criterion to establish a medium impact rating that would include a lower bound to the criterion. Control Centers with the characteristics listed below would be categorized as assets that contain medium impact BES Cyber System(s), and all others would be identified as low impact BES Cyber System(s). The impact rating criteria would be similar to the NERC proposed beta criteria referenced above. One example of a revised criterion 2.12 is as follows:

Attachment 1: criterion 2.12. Each control center or backup control center not included in the high impact rating (H) above, that is used to operate any of the following:

- Two geographically separate (BES) Transmission Facilities operated at 200 kV or higher
- Transmission Facilities that have an aggregate transmission capacity greater than 1500 MVA
- A Facility that has been identified by its RC, PC, or TP as critical to the derivation of an Interconnection Reliability Operating Limit (IROL) and its associated contingencies
- Facilities operated between 100 and 200 kV that have been identified as part of a permanent flow gate or major transfer path
- BES Transmission Facilities that have a Total Transfer Capability with a neighboring Transmission Operator that is greater than 1500 MVA
- Greater than 200 line miles of Transmission Lines

The SDT assessed the potential for such a revision to the criteria and found trade-offs to the proposal. This option could provide added clarity for Responsible Entities and compliance enforcement personnel in determining the assets that are in and out of scope; however, this option could still cause Control Centers with minimal risk to the BES to be identified as medium impact BES Cyber System(s). This could place significant strain on resources of minimal risk entities and the burden as well as benefit may not be commensurate to the risk of those entities.

There will be implications for both newly registered TOs as well as existing TOs. Updated criteria will trigger an analysis and implementation cycles for entities currently in scope under CIP V5 causing rework depending on what type of criteria might be considered. This is a significant consequence for entities that only recently completed implementation of CIP V5 or will still be in the process of completion of the implementation efforts. The update could likely change the impact classification of affected BES Cyber System(s). While this would be one purpose of the revision, resolution for some would be offset by new issues for others.

While the SDT is considering development of a categorization for Control Centers with a low impact rating, FERC Order No. 706 set an expectation that Control Centers would be identified as "Critical Assets," which correspond to high and medium impact levels in the revised CIP Reliability Standards. Given the overhaul that CIP V5 represents in its expansion of scope to include all BES Cyber Systems, a lower bound for Control Centers may be justifiable.

b) Low Impact Justification Process

Another potential solution is to utilize a justification process that would provide Responsible Entities the opportunity to demonstrate that their Control Center poses a minimal risk/low impact to the BES. As contemplated, a justification process may allow the TO to perform an engineering analysis to demonstrate to the ERO Enterprise that the risk posed by its Transmission Facilities do not warrant protection of the associated BES Cyber System(s) as medium impact. The criteria upon which the ERO would assess the TO's analysis would need to be developed. This justification process could include a review of the TO's analysis by an unaffiliated third party.

This justification process approach could provide the clarity requested by the V5TAG and could also provide Responsible Entities a process to demonstrate its actual impact level as demonstrated by engineering studies. However, this additional process could place additional strain on limited resources for Responsible Entities and Compliance Enforcement Authorities to support the positions that certain Control Centers represent less risk or impact to the Bulk Electric System even in a situation specific to misuse or malicious threat actors.

2) No further action by the SDT

The V5TAG presented a valuable opportunity for NERC, the Regions and industry to consider the CIP V5 language under implementation and consider areas that may benefit from added clarity. However, the SDT evaluation must take into account the breadth and diversity of the entities to which the CIP V5 language applies. The language under evaluation by the SDT relative to the TOCC issues raised by the V5TAG was approved by NERC stakeholders through an open and transparent process. The current state reflects that FERC approved language is in effect and currently no direction to modify the language has been given.

In addition, CIP V5 only became mandatory and enforceable on July 1, 2016. Familiarity with the full implications and effectiveness of the standards is still new and untested.

From research and analysis, the option to take no further action could potentially be based on the following reasons:

- The TOCC situation represents individualized company positions and each entity must be evaluated for risk and impact suggesting a widely applicable standard is not appropriate to represent a norm or majority.
- The currently approved language maintains the intent of the CIP V5 language.
- Revision of the Control Center definition is not needed to resolve this issue and has broader implications that are not limited to this project.
- Standards development should not be utilized to solve potential concern about compliance monitoring or enforcement. Alternative ERO tools exist such as the BES Exception Process and NERC led review panels related to Risk Based Registration Processes should be pursued to resolve entity concerns before revising the approved and implemented standard language. If there is validity or need to open the standards for revision, the SDT is asking for this specific feedback.

The SDT understands that, absent an action not proposed within this TOCC White Paper, a decision to take no further action on the TOCC issue area confirms the existing criteria in CIP-002-5.1a Attachment 1, including criterion 2.12 which identifies all BES Cyber System(s) associated with TOCCs performing the functional obligations of a TOP as medium impact.

Next Steps

The SDT requests industry stakeholders consider the discussion and options detailed above and provide informal comments to the SDT. Input to the comment form questions will help confirm the influential facts and circumstances around this issue and aid the SDT in determining recommended actions.

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Unofficial Comment Form

Project 2016-02 Modifications to CIP Standards Virtualization in the CIP Environment

Do not use this form for submitting comments. Use the electronic form to submit comments on the **use of Virtualization in the CIP environment**. The electronic form must be submitted by **8 p.m. Eastern, Tuesday, April 11, 2017**.

Additional information is available on the project page. If you have questions, contact Mat Bunch (via email) or at (404) 446-9785.

Background Information

On January 21, 2016, the Federal Energy Regulatory Commission (Commission) issued Order No. 822, *Revised Critical Infrastructure Protection Reliability Standards,* approving seven CIP Reliability Standards and new or modified definitions. On March 9, 2016, the NERC Standards Committee authorized a Standards Authorization Request (SAR) to be posted for a 30-day informal comment period from March 23 – April 21, 2016. Based on the comments received, the Standard Drafting Team (SDT) made minor revisions to the SAR which was posted for an additional 30-day informal comment period June 1-30, 2016.

The purpose of this project is to; (1) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the CIP V5 Issues for Standard Drafting Team Consideration (V5TAG Transfer Document), and (2) address the Commission directives contained in Order 822. These revisions will increase reliability and security to the Bulk Power System (BPS) by enhancing cyber protection of BPS facilities.

The V5TAG, which consisted of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry's implementation activities. During the course of the V5TAG's activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by the existing SDT for the CIP Reliability Standards. The V5TAG developed the V5TAG Transfer Document to formally recommend that the SDT address these issues during the standards development process and to consider whether modifications can be made to the standard language.

The current informal posting document is an effort to gather input on the V5TAG issue related to virtualization in the CIP environment. The CIP standards are based primarily on concepts dating back to Version 1 and as technology has evolved, issues have begun to arise as entities attempt to take new concepts and fit them into some of the Version 1 paradigms. These issues revolve around topics such as:

- Hypervisor – the virtualization component that manages the guest operating systems (OSs) on a host and controls the flow instructions between the guest OSs and the physical hardware.

- Virtual machines – With virtualization technologies, a single physical Cyber Asset can be used as an execution platform for numerous virtualized operating systems, micro-service containerized applications, and virtual network functions of all classifications. A single physical Cyber Asset can appear to an external network as many complete Cyber Assets. Virtual switches and networks can be defined so these virtual machines can communicate with each other as if they are separate physical nodes on the network. Virtual machines and functions can also migrate around a physically clustered cyber system such that the singular physical Cyber Asset where an application resides can change at any moment.

  The virtualization of Cyber Assets provides advantages for the availability, resiliency, and reliability of applications and functions hosted in such an environment and the CIP standards must not stand in the way of these benefits as long as they are implemented in a secure manner. Virtualization affords enhanced security in some cases as the security controls themselves can be virtualized and placed within the virtual environment closer to the workloads they are protecting. However, there are also different security risks introduced by these environments. The management systems or consoles for these environments allow for the complete control of numerous components of the infrastructure. Virtual machines or networks can be added, modified, or deleted from one central management system. For example, rogue virtual components can starve legitimate workloads of the shared resources (processor, memory, etc.) they need to reliably perform their function. In summary, changes to the CIP Requirements may be needed to account for virtualization.
- Virtual Networks – Electronic Security Perimeter (ESP) constructs within the current CIP standard are limited to defining security zones at Open Systems Interconnection (OSI) Layer 3 and do not support security zones defined at layers other than OSI Layer 3. With current, widely deployed technology, networks are no longer solely defined by the arrangement of physical hardware and cables *inside* or *outside* of a *perimeter*. Networks can exist as a mixture of physical and virtual segments or purely in a virtual state within one device. Virtual firewalls and other security tools are also available to help secure these environments. Typical hardware network switches can be configured with internal logical isolation to implement multiple virtual networks within them. Accordingly, the SDT is reviewing the CIP standards to validate that definitions, requirements, and guidance regarding ESPs and Electronic Access Points (EAPs) continue to provide for secure and reliable operations.
- Virtual Storage – Historically, servers were limited to dedicated storage within the device. Typically, the operating system and the applications resided in the server on hard drives. Virtual storage technologies such as Storage Area Networks (SANs) present virtualized logical drive storage units to all attached servers. These types of environments then become a shared resource among many physical and virtual hosts.

With all of this in mind, the SDT is considering:

1) Areas in the current CIP requirements that might prevent or hinder the adoption of virtualization technologies for BES Cyber Systems and related systems;
2) Areas of new risks introduced by virtualization technologies and how to address them in the standards.

Questions

The SDT has determined that some of the concepts in CIP Version 5 must be fully realized in order to support virtualization. For example, while Version 5 introduced the "cyber system" concept and most requirements are now written at the cyber system level, the advantages of this approach have not been fully integrated into all levels of planning, design or compliance assessment approaches. Most entities still manage their CIP programs at a device level and auditors still look for device-centric evidence of compliance. This paradigm poses substantial issues with the use of virtual technologies. Infrastructure resources are pooled, apportioned to a given workload, and withdrawn or re-assigned when no longer needed. Infrastructure components (including instances of operating systems) come and go according to the current workload, making individual Cyber Asset level inventories difficult or impossible. The mobility of these resources makes permanently describing their physical locations problematic. Hardware (both computer and network) becomes a general-purpose commodity — merely a pool of resources on top of which the actual infrastructure is designed and created at a logical/virtual level. As technology increasingly blurs the line between physical and virtual systems, managing compliance in terms of individual devices or Cyber Assets becomes more challenging.

1. Version 5 introduced the BES Cyber System concept, and requirements reference applicability at the *BES Cyber System* level. However, language in the measures shows that, implicitly, many controls are expected to be implemented at the *BES Cyber Asset* or *device* level. The SDT assumes that most auditors expect entities to demonstrate compliance at the device level. Do you agree with the SDT's assumption? If so, how should the SDT address these inconsistencies?

   ☐ Yes
   ☐ No

   Comments:

To incorporate virtualization and address the V5TAG transfer issue to clarify the meaning of the term *programmable* in the current definition of *Cyber Assets*, the SDT is proposing changes to the definition that include defining the term in the singular rather than the plural. Updating the definition to include virtual environments allows the definition of other terms based on *Cyber Asset*, such as Electronic Access Control or Monitoring Systems (EACMS) and Protected Cyber Asset (PCA) to also include virtual environments.

The proposed *Cyber Asset* definition is:

Redlined

~~*Programmable*~~*An electronic device*~~*s*~~ *(physical or virtual) whose operation is controlled by a stored program that can be changed or replaced by the end user, including the hardware, software, and data in* ~~*those devices*~~ *the device. A virtual machine is itself a distinct asset from its host(s).*

Clean

An electronic device (physical or virtual) whose operation is controlled by a stored program that can be changed or replaced by the end user, including the hardware, software, and data in the device. A virtual machine is itself a distinct asset from its host(s).

2. The SDT proposes that each virtual machine and hypervisor are separate Cyber Assets. Do you agree with this position? Please provide a rationale to support your position.

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree that the proposed Cyber Asset definition clarifies the term *programmable*? Please provide a rationale to support your position.

   ☐ Yes
   ☐ No

   Comments:

In virtualized environments, the physical infrastructure can be shared between BES Cyber Systems and other non-CIP Cyber Assets while maintaining isolated virtualized environments for each.

4. Such configurations are not addressed explicitly in CIP-005-5. Are modifications required to address the issue? Please provide your rationale.

   ☐ Yes
   ☐ No

   Comments:

Concerning virtual networks, network devices can have multiple logical networks configured (e.g. virtual local area networks (VLANs)). Physical or virtual devices perform "logical isolation" when configured such that some network interfaces are available inside an ESP, and other interfaces are outside an ESP and the two networks cannot communicate with each other inside of the device. This would not prevent the VLANs configured inside the device from communicating through an EAP.

5. The SDT asserts that VLANs providing logical isolation are not addressed explicitly in CIP-005-5, and controls may be necessary to isolate BES Cyber Systems. Are the current requirements of CIP-005-5 sufficient to address logical isolation using VLANs? Please provide your rationale.

   ☐ Yes
   ☐ No

   Comments:

The SDT has identified certain risks inherent to virtualization regarding the use of centralized management automation. The SDT is proposing to classify *Centralized Management System* (CMS) explicitly as a type of applicable system for some CIP requirements. In examining management architecture and risk management for virtual environments, the SDT identified an increased risk inherent to the span of control of hypervisor management consoles. Further, the SDT noted that similar risks exist in CMSs used to manage physical devices, and recognized these risks may not be fully addressed in current CIP standards and the *EACMS* definition. The SDT is considering a new definition of this class of system.

The proposed *Centralized Management System* (CMS) definition is:

> *A centralized system for administration or configuration of BES Cyber Systems, including but not limited to systems management, network management, storage management, or patch management.*

6. Do you agree with the proposed definition of CMS? If not, please provide alternative language for the definition and your rationale.

   ☐ Yes
   ☐ No

   Comments:

7. Do you agree with the SDT's approach to reference the CMS specifically as a type of applicable system in the CIP standards? Please provide your rationale.

   ☐ Yes
   ☐ No

   Comments:

In examining virtualization, the SDT considered centralized management systems or consoles for these environments. These systems allow for the mass addition, deletion and modification of virtual machines and networks. Access to the control surface of a cyber system is known as the *management plane*. The management plane is where the virtual infrastructure is configured and managed by a limited group of administrators as opposed to the *data plane*. The data plane is where the end user's access to the virtual machine's business function takes place. To meet the security objective of protecting a BES Cyber System from threats in the data plane, the management plane should be isolated from the data plane. These types of controls are referred to as *out of band* management.

The SDT is considering limiting the scope of management plane protection requirements to high and medium impact Control Centers because these environments contain the highest risk.

8. Do you agree with the SDT's approach to require the isolation between the data plane and the management plane? Please provide your rationale.

   ☐ Yes
   ☐ No

   Comments:

9. Do you agree with limiting the applicability to high and medium impact Control Centers? Please provide your rationale.

   ☐ Yes
   ☐ No

   Comments:

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

Anticipated Actions	Date
30-day informal comment period with ballot	April 2017
45-day formal comment period with additional ballot	July 2017
45-day formal comment period with additional ballot	October 2017
10-day final ballot	December 2017
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):

~~Text~~ 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:** **See Implementation Plan.** ~~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.~~

~~6. 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.~~

~~7. 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:~~

~~8. P1-2 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~

~~9. P1-3 (for controlled interruption of electric supply to local network customers connected to or supplied by the Faulted element)~~

~~10. P2-1~~

~~11. P2-2 (above 300 kV)~~

~~12. P2-3 (above 300 kV)~~

~~13. P3-1 through P3-5~~

~~14. P4-1 through P4-5 (above 300 kV)~~

~~15.~~5. ~~P5 (above 300 kV)~~

~~16. Background: Text (DELETE GREEN TEXT PRIOR TO PUBLISHING) This section is to only be used for standards that currently have a background section. Going forward standard drafting teams should avoid using this section.~~

~~17. Standard-Only Definition: Text (DELETE GREEN TEXT PRIOR TO PUBLISHING) This section is to only be used for standards that currently have standard only definitions. Going forward a standard must provide a justification as to why the standard needs a standard-only definition and cannot be moved to the NERC Glossary of Terms.~~

B. Requirements and Measures

Rationale for Requirement R1:

References to MOD-010 and MOD-012 in Requirement R1 have been replaced with MOD-032, which is now the applicable standard to assemble the network modeling data necessary to meet the TPL-001 requirements. MOD-032-1 superseded MOD-010 and MOD-012, which were retired on 6/30/2016 in the United States.

Rationale for Requirement R1 Part 1.1.2:

In Order 786, Federal Energy Regulatory Commission (FERC) directed 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" (P 40). The Commission clarified that its directive is to "include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages" (P 42). FERC stated that NERC had flexibility in addressing the identified concerns and outlined three acceptable approaches, that include:

1. "eliminating the six-month threshold altogether";
2. "decreasing the threshold to fewer months to include additional significant planned outages"; or
3. "including parameters on what constitutes a significant planned outage based for example on MW or facility ratings."

See Order No. 786 at P 43.

Order 786 includes the following additional concerns:

- Planned maintenance outages less than six months may result in impacts during peak and off-peak periods (*see* P 41);
- 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 (*see* P 41);
- Criticality of elements taken out for maintenance could result in N-1 outage and loss of non-consequential load or impact to reliability (*see* P 41);
- 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) (*see* P 42);
- Relying on Category P3 and P6 is not sufficient and does not cover maintenance outages (*see* P 44);
- The 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 (*see* P 45).

The change to Requirement 1 Part 1.1.2 eliminates the specified 6 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.

Note: The drafting team points out that this is coordination of known outages beyond the Operations Planning.

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~~s~~, 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 ~~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

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 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.

Rationale for Requirement R2 Part 2.4.5:

In Order No. 786, FERC stated that it believed a stability analysis for spare equipment strategy should exist, similar to the steady state analysis under TPL-001-4 Requirement 2 Part 2.1.5 (*see* P 89). The SDT modified the standard to add R2.4.5, which includes similar language to that used for the steady-state analysis under R2.1.5.

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, as selected in consultation with the ~~as directed~~ Reliability Coordinator, with ~~the~~ known outages modeled as specified 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. The studies 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.

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 studied. The studies shall be performed for the 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.

2.5. 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
- 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. 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. 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.

Rationale for Requirement R4 Part 4.6:

The SPF of a non-redundant Protection System component is a relevant reliability concern for the electrical utility industry and have been identified as the cause of significant system disturbances in past years. (*See Industry Advisory-Protection System Single Point*

of Failure, Informational Filing of the North American Electric Reliability Corporation in Response to Order No. 754, Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request). The changes herein clearly establish the TPL-001 standard as requiring corrective actions for Planning Events for which a single point of failure of a non-redundant component of a Protection System, as described by footnote 13. The drafting team took into consideration the recent history of attention given to single point of failure and the tradeoffs with incorporating the 3Ø fault with failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing into the existing P5 or similar, Table 1 event. Consistent with the concerns expressed in FERC Order No. 754, the drafting team decided to maintain the 3Ø fault event in the extreme event section of Table 1, while incorporating a specific Requirement R4 Part 4.6 to develop Corrective Action Plan when analysis concludes that Cascading is caused. By featuring the extreme events 2e-2h listed from the stability column of Table 1 in Requirement 4 Part 4.6, this highlights the single point of failure of a non-redundant component of a Protection System resulting in Delayed Fault Clearing as having higher risk than other extreme events, but only demanding corrective action if observed to cause Cascading. This is a reasonable balance of likelihood of the event and its consequences. In this way, the drafting team intends for the extreme events 2e-2h listed from the stability column of Table 1 that cause Cascading to require correction, most likely through Protection System modifications, not simply be evaluated for possible actions designed to reduce the likelihood or mitigate the consequences of the extreme event, in accordance with Requirement R4 Part 4.5.

A planner is permitted to use engineering judgment to select the Protection System component failures for evaluation that would produce the more severe system results or impact, and the evaluation would address all Protection Systems affected by the selected component. A Protection System component failure that impacts one or more Protection Systems and increases the total fault clearing time requires a planner to simulate the full impact (clearing time and facilities removed) on Bulk Electric System performance.

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 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.

4.3. 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. 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. 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. 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.

4.6. If the analysis concludes there is Cascading caused by the occurrence of Table 1 extreme events listed in the stability column for events 2e-2h, a Corrective Action Plan shall be developed. The Corrective Action Plan shall:

4.6.1. List ~~s~~System deficiencies and the associated actions needed to prevent the ~~s~~System from Cascading.

4.6.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

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.

C. Compliance

1. Compliance Monitoring Process

~~17.1.~~1.1. Compliance Enforcement Authority:

~~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.

~~17.2.~~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 identified in Measures M1 through M7 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.

~~17.3.~~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.

~~17.4.~~

~~17.5.~~

~~17.6.~~1.4. ~~1.2~~ **Compliance Monitoring Period and Reset Timeframe:**

Not applicable.

~~17.7.~~

~~17.8.~~1.5. ~~**Compliance Monitoring and Enforcement Processes:**~~

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

~~**17.9.Data Retention:**~~

~~The Transmission Planner and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.~~
- ~~The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.~~
- ~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.~~
- ~~The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.~~
- ~~The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.~~
- ~~The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.~~
- ~~The current, in-force documentation for the agreement(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.~~

~~The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:~~

- ~~Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8.~~
- ~~If a Transmission Planner or Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.~~

~~17.10.~~1.6. Additional Compliance Information:

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.
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 4.2 -to assess the impact of extreme events.	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 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 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 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.

D. Regional Variances

None.

E. Associated Documents

Link to the Implementation Plan and other important associated documents. **(DELETE GREEN TEXT PRIOR TO PUBLISHING) A link should be added to the implementation plan and other important documents associated with the standard once finalized.**

Rationale for Table 1 P5 Event and Footnote 13:

The revisions to Table 1 Category P5 event require an entity to model a single point of failure of a non-redundant Protection System component that may prevent correct operation of a Protection System, including other Protection Systems impacted by that failed component based on the as-built design of that Protection System. The evaluation shall address all Protection Systems affected by the failed component and the increases (if any) of the total fault clearing time. Footnote 13 provides the attributes of the specific system component failure that the entity shall consider for evaluation.

Changes to the Table 1 P5 event and related footnote 13 are driven by subsequent results of an assessment of Protection System single points of failure in response to FERC Order No. 754. In paragraph 19 of Order No. 754, FERC stated that there is "an issue concerning the study of the non-operation of non-redundant primary Protection Systems; e.g., the study of a single point of failure on Protection Systems." NERC subsequently issued a NERC Section 1600 Request for Data or Information, the results of which were analyzed by the System Protection and Control Subcommittee (SPCS) and the System Modeling and Analysis Subcommittee (SAMS). In their 2015 report "*Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request*," the SPCS and SAMS considered a variety of alternatives to address the reliability risk posed by single points of failure. SPCS and SAMS concluded that the most appropriate recommendation aligning with Order No. 754 directives and maximizing reliability of Protection System performance included modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) through the NERC standards development process.

The SPCS/SAMS report made the recommendations to replace “relay” with “component of a Protection System” in the Table 1 P5 event and replace footnote 13 in TPL-001-4 with 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. 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.

The drafting team sought to limit the scope of protective relays which respond to electrical quantities that may be considered non-redundant components of a Protection System that may experience a single point of failure to those relays that are used for primary protection at the local terminal and applied over the element in question. As typical Protection System designs implement backup protective relaying locally and remotely, the drafting team did not include backup protective relays or overlapping zonal protection as components of a Protection System specified in footnote 13.

Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping 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 Performance Requirements, enumerated in Table 1 of TPL-

001-5. In other words, a communication-aided Protection System that may experience a 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-001-5 standard.

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.	**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.

ii. Loss of the use of a large body of water as the cooling source for generation. 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
    2. A single communications system, necessary for correct operation of protective functions, 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 through 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:

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)
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.

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 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.	

Version	Date	Action	Change Tracking
		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.

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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 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, 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 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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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:	PRC-025-1 – Generator Relay Loadability		
Date Submitted:	August 25, 2016		
SAR Requester Information for #1			
Name:	Rich Quest		
Organization:	Midwest Reliability Organization		
Telephone:	(651) 855-1704	Email:	rp.quest@midwestreliability.org
SAR Requester Information for #2			
Name:	Jerry Thompson, E.I.T.		
Organization:	Kestrel Power Engineering		
Telephone:	(571) 293-1119	Email:	jerry@kestrelpower.com
SAR Requester Information for #3			
Name:	Joe DePoorter		
Organization:	Madison Gas & Electric		
Telephone:	(608) 252-1599	Email:	JDePoorter@mge.com

Request to propose a new or a revision to a Reliability Standard			
SAR Requester Information for #4			
Name:	Éric Loiselle, ing.		
Organization:	Hydro-Québec TransÉnergie		
Telephone:	(514) 879-4100	Email:	Loiselle.Eric2@hydro.qc.ca
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?):
This SAR proposes revising PRC-025-1 ~~for four~~the following specific problems. 1. Prevent instances of non-compliance for conditions where the Generator Owner may be prevented from achieving the margin specified by the standard for dispersed ~~generation~~power producing resources ~~(DGR).~~. 2. Prevent a lowering of reliability and potential non-compliance where the Generator Owner might apply a non-standard relay element application and undermine the goal of the standard. 3. Prevent a lowering of reliability where the Generator Owner might only apply part of the Table 1 application(s) thereby misapplying the loadability margins to relays for the stated application(s). 4. Prevent a lowering of dependability of protective relays directional toward the ~~transmission~~Transmission system at generating facilities that are remote to the transmission network. 5. Modify or eliminate the use of the term “pickup setting” and other terms or phrases that relate to initial measurements and specific detection methods, and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to “not trip” based on the criteria in Table 1. ~~4.~~6. Miscellaneous considerations for clarifications to the standard, Attachment 1, and/or Application Guidelines.

SAR Information
Purpose or Goal (How does this request propose to address the problem described above?):
Consider revising the PRC-025-1 standard through the standards development process to: (1) provide alternative loadability Options for Table 1 specific to ~~DGR~~dispersed power producing resources; (2) address the inclusion or exclusion of the 50 element[1] (i.e., instantaneous), (3) review Table 1 for proper application where there is more than one application for the available Option(s), ~~and~~ (4) provide alternative or additional Options for Table 1 specific to relay applications that are directional toward the ~~transmission~~Transmission system where the interconnecting transmission line impedance may be a factor in determining the maximum ~~reactive~~Reactive Power output of the generators and associated relay settings, (5) provide an alternative to the term "pickup setting" in Table 1 the will better align with the intent of the standard for relays to "not trip", and (6) provide clarity on identified miscellaneous items.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
This SAR proposes the need for revising PRC-025-1 for ~~four~~the following specific problems. 1. PRC-025-1, Table 1 requires setting the overcurrent relay of a Protection System applied to an asynchronous generating unit or an Element utilized in the aggregation of ~~DGR~~dispersed power producing resources to a margin greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor. This may result in instances of non-compliance due manufacturer requirements or physical limitations of ~~DGR~~dispersed power producing resources and may result in an overly conservative relay setting. Consider revising the standard to provide alternative options for setting the overcurrent element of a Protection System applied to an asynchronous generating unit and an Element utilized in the aggregation of ~~DGR~~dispersed power producing resources. 2. There is potential for Generator Owners to apply a pick up setting of the 50 element (i.e., instantaneous overcurrent) of a Protection System, which is not applicable to the standard, that is lower than the minimum pick up established by the standard for the 51 element (i.e., time delayed overcurrent). The 50 element is generally not used in the generator applications where the 51 element is found in the standard. In addition, there are some applications in which protective functions utilized measure and react to current but do not use ANSI device numbers.

[1] Refer to Institute of Electronics and Electrical Engineers (IEEE) Standard C37.2-2008 for American National Standards Institute (ANSI) device numbers.

SAR Information
Consider revising the standard to address the inclusion or exclusion of the 50 element and other similar elements that may not use ANSI device numbers for the various overcurrent applications within Table 1. 3. There is potential for Generator Owners not to apply loadability margins to all load-responsive protective relays in Table 1 of PRC-025-1 under the "Application" column that may affect loadability. For example, the Application column from Table 1 (Options 4, 5, and 6): *"Asynchronous generating unit(s) (including inverter-based installations),* ***or*** *Elements utilized in the aggregation of dispersed power producing resources."* The above clause is separated by an "or" conjunction and may lead the Generator Owner to set one particular application and not the other. This may create a gap in achieving the goal of the standard when loadability margins are not applied to relays on certain Elements. Consider revising the standard to make it clear whether either or both of the listed Elements in the Application column of Options 1-6 must meet the criteria of the particular Option. For "Elements utilized in the aggregation of dispersed power producing resources", clarify that the standard is requiring an assessment from each generating source through the feeders and up through the interconnecting transmission line by adding a bulleted list. Alternatively, develop a section of Table 1 that specifically addresses relays applied on these Elements, making certain it is clear this statement applies to feeders in collection systems, and potentially then removing this statement from the current Options 1-6. 4. In the case of remote generating facilities that are electrically weak at its connection to the transmission network, the maximum ~~reactive power~~Reactive Power required by the specific Table 1 Options is too high to be observed in any recoverable stressed condition. This is due to the system impedance (mainly line impedance) restricting the maximum ~~reactive power~~Reactive Power output by the generator, no matter the generator characteristics. Lastly, applying the existing Table 1 Options for relay applications directional toward the ~~transmission~~Transmission system results in an overly conservative relay setting and could require reducing the backup protection coverage in order to comply with the stressed system condition anticipated by the standard. 5. The use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods does not align with the intent of the standard for relays to "not trip" based on the criteria in Table 1. Clarify that multiple methods/curve types are acceptable so long as the applied protection does not trip the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of

SAR Information
blinders, non-mho relay characteristics and other schemes in which the relay's initial measurement may detect a condition (e.g., may "pickup") but the relay is blocked from operating. 6. Miscellaneous items that may result in a lack of clarity in the standard, Attachment 1, and/or the Application Guidelines: a. It is not clear that the ANSI device numbers within the standard refer to the IEEE Standard C37.2-2008 reference document. Adding an appropriate reference will improve clarity. b. It is unclear when resources are described with the following terms in the Standard: asynchronous, synchronous, inverter-based, and dispersed power producing resources. The description of what is classified as an asynchronous generator should be clarified. For example, the statement in Application Guidelines that "asynchronous generators… 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" should be clarified/corrected or replaced since this category is intended to include inverter based, doubly-fed induction generator based, and induction generator based resources. Clarify the proper treatment of various resources. c. It is not clear that the phrase about unit capability "reported to the Transmission Planner" is a minimum criterion and that a greater unit capability is acceptable. Clarify that the Generator Owner may base settings on a capability higher than what is reported to the Transmission Planner. ~~a.~~d. It is not clear that CB103 relay in Figure 1 of the Application Guidelines is applicable to the standard because the Application Guidelines only addresses a directional relay toward the generator plant as not being applicable; however, there are cases where CB103 would be applicable to the standard (e.g., non-directional relays). Provide clarity that would help prevent the overlooking of the CB103 relay as being applicable to the standard, including a potential revision to Figure 1.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The PRC-025-1 standard became effective on October 1, 2014 and has a phased implementation of five and seven years (i.e., 2019 or 2021) depending on the scope of work required by the Generator Owner. During the early stages of implementation, the above ~~four~~ problems were revealed by industry. The scope of work will be to consider providing (1) an alternative loadability margin for ~~DGR~~dispersed power producing resources, (2) revision that includes or excludes 50 element for overcurrent applications, (3)

SAR Information
clarification of the application of the Elements in Table 1 of PRC-025-1 for each option that has two applicable Elements separated by an "or" conjunction, ~~and~~ (4) alternative or additional Option(s) (e.g., calculation or method) for determining loadability settings for relays that are directional toward the ~~transmission.~~Transmission system, (5) modify or eliminate the use of the term "pickup setting," and (6) miscellaneous consideration of clarifications to the standard, Attachment 1, and/or Application Guidelines.
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.)
1. Consider revising the PRC-025-1 standard concerning #1 above through the standards development process to provide a means to determine alternative loadability Options for Table 1 of the standard specific to ~~DRG equipment~~dispersed power producing resources where there could be a manufacturer requirement or physical equipment limitation. Similar to the provisions already contained in the standard, consider methods that would eliminate the potential for non-compliance and/or a violation of manufacturer specifications. For example: (a) a provision could allow a margin consistent with the manufacturer's requirements or based on the limitation of the equipment; (b) a provision to allow the ~~DRG~~dispersed power producing resource output to be studied through simulation (e.g., similar to Options 1c and 2c) and the relays to be set with an appropriate margin determined through the standard development process; (c) a provision to exempt equipment with fixed limitations installed prior to the effective date of PRC-025-1 or other justifiable date; and/or (d) any other equally effective and efficient method to accomplish the goal.[2] 2. Consider revising the PRC-025-1 standard concerning #2 above to address the inclusion or exclusion of the 50 element (i.e., instantaneous overcurrent) of a Protection System, and other overcurrent type elements which may not utilize ANSI device numbers, with or without intentional time delay. Newer techniques in generator protection applications and differences in protective elements applied with different generation technologies may result in a gap due to non-traditional applications of generator overcurrent relays.

[2] Any criteria revised in the standard concerning dispersed power producing resources should also be considered for Elements utilized in the aggregation of dispersed power producing resources, if separated from the dispersed power producing resources application of Table 1.

SAR Information
3. Consider revising the PRC-025-1 standard concerning #3 above through the standards development process to bring awareness and clarification ~~whether either or~~that both of the Elements listed in the "Application" column of Table 1, Options 1-6 are to have loadability margins applied to the load-responsive protective relays. 4. Consider revising the PRC-025-1 standard concerning #4 above through the standards development process to provide a means to determine alternative loadability Option(s) for Table 1 of the standard specific to relays directional toward the ~~transmission~~Transmission system. Similar to the provisions already contained in the standard, consider: (a) alternative Options for relay settings where the interconnecting transmission line impedance has a significant impact the maximum ~~reactive~~Reactive Power output of the generating facility and the associated relay settings, (b) the technical validity of the existing options in the presence of significant transmission line impedance between generation and the network, and/or (c) any other equally effective and efficient method to address the problem of significant line impedance effecting how phase protective relays are set not limit generator loadability while maintaining reliable protection of the BES for all fault conditions. 5. Consider revising Table 1 to modify or eliminate the use of the term "pickup setting" and other terms or phrases that relate to initial measurements and specific detection methods and instead, use a term or phrase that clearly aligns with the intent of the standard for relays to "not trip" based on the criteria in Table 1. Consider clarifying wherever necessary that multiple methods/curve types are acceptable so long as the applied protection does not trip the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of blinders, non-mho relay characteristics and other schemes in which the relay's initial measurement may detect a condition (e.g., may "pickup") but the relay is blocked from operating. 6. Miscellaneous considerations for the standard, Attachment 1, and/or Application Guidelines: a. Consider including a reference in the standard to clarify that the ANSI device numbers within the standard refers to IEEE Standard C37.2-2008 reference document. b. Consider whether it is clear and appropriate when resources are described with the following terms in the Standard: asynchronous, synchronous, inverter-based and dispersed power producing resources. The description of what is classified as an asynchronous generator should be clarified. For example, Asynchronous generators do not have excitation systems and will not respond to a disturbance with the same

SAR Information
magnitude of apparent power that a synchronous generator will respond; therefore, are treated as "asynchronous" in Table 1. c. Consider clarifying the use of the phrase about unit capability "reported to the Transmission Planner" as being a minimum criterion and that a greater unit capability is acceptable. ~~a.~~d. Consider clarifying that CB103 relay in Figure 1 of the Application Guidelines is applicable to the standard and correct the figure to show CB103 as also possibly being subject to the standard. The Application Guidelines only addresses a directional relay and that non-directional relays would be applicable to the standard.

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).

Reliability Functions		
☒	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.
☐	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

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Periodic Review Recommendations: VAR-001-4.1 – Voltage and Reactive Control

February 13, 2017

Executive Summary

The periodic review team completed a comprehensive review of VAR-001-4.1 – Voltage and Reactive Control. The team found 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. The following are the observations and recommendations of the periodic review team.

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 (ANSI) 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 (SC) for periodic reviews, and a stakeholder Subject Matter Expert (SME) team. Consistent with Section 13 of the Standards Processes Manual (SPM)[2], the SC may use a public nomination process to appoint the stakeholder Subject Matter Expert (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 SPM.

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[1] American National Standards Institute website: https://www.ansi.org/ http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

[2] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Review Team Composition

	Standing Review Team	Plus Section 13 (SMEs):
Non-CIP Standards	Chairs of the following NERC Standing Committees[3]: • SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team)[4] • Planning Committee • Operating Committee (A regional representative will be included on the Standing Review Team.) The Standing Review Team will meet with SMEs and help to ensure a consistent strategy and approach across all of the reviews.	The SC will appoint stakeholder SMEs 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.
CIP Standards	Chairs of the following NERC Standing Committees[5]: • SC (Also the SC chair or his/her delegate from the SC will chair the Standing Review Team) • CIPC	The SC will appoint stakeholder SMEs 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 re-affirming the standard as steady-state (Green); or

[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.

[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.

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 Scott Barfield-McGinnis via email or by telephone at 404-446-9689.

Applicable Reliability Standard: VAR-001-4.1 & VAR-002-4
Team Members (include name and organization): 1. Stephen Solis (Chair), Electric Reliability Council of Texas, Inc. 2. Dennis Sauriol (Vice Chair), American Electric Power 3. Alex Chua, Pacific Gas and Electric 4. Kevin Harrison, ITC Holdings 5. Bill Harm, PJM Interconnection, LLC 6. Tim Kucey, PSEG Fossil, LLC 7. Michael Scott, NextEra Energy, Inc.
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

   Please explain:

   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 obvious 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 (RAI) 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:

   Requirement R4 does not require periodic review of the exemption or review triggered by other changes such as changes in technology, system conditions or other factors, this may require a periodic review of the exemption criteria; and the generators that may have been exempted by the Transmission Operator.

   For Requirement R5, the Generator Operator may need to raise concerns to the Transmission Operator over the inability to meet the voltage schedule. This concern may result in an exemption, voltage schedule revision, or possibly some other action. This concern could be addressed with a revision to the Standard or some equivalent technical guidance (e.g., guideline). The requirement does not have a feedback loop to raise such concerns.

   Requirement R2 requires the Transmission Operator to maintain sufficient reactive resources to regulate voltage levels under normal and Contingency conditions. The standard's purpose statement notes that reactive resources among other things are monitored. There does not appear to be a requirement to monitor reactive resources (i.e., reserves) to ensure sufficiency.

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?

   ☒ Yes

☐ No

Guiding Questions:

a. If the Reliability Standard is applicable to Generator Owners (GOs) and/or Generator Operators (GOPs), 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.)

Response: The standard is not applicable to GOPs continent-wide and only GOPs according to the Western Interconnection variance in the standard. There is no ambiguity about the inclusion of generator Interconnection Facilities.

b. If the Reliability Standard is not applicable to GOs and/or GOPs, is there a reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard? (If so, GOs that own and/or GOPs that operate relevant generator Interconnection Facilities should be explicit in the Applicability section of the Reliability Standard.)

Response: The standard is applicable to Transmission Operators. There is no reliability-related need for treating generator Interconnection Facilities as Transmission Lines for the purposes of this Reliability Standard.

c. If the Reliability Standard is applicable to Transmission Operators (TOPs) and/or Distribution Providers (DPs), 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.)

Response: The standard is applicable to Transmission Operators. There is no ambiguity about the inclusion of Transmission Interconnection Facilities.

9. **Results-Based Standard (RBS):** Is the Reliability Standard drafted as a RBS?

☒ 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:

As VAR-001-4.1 Requirement R5 is written, the Transmission Operator (TOP) has flexibility to determine the duration that a generator can be outside the voltage bandwidth. A TOP may have varying criteria depending on the specific unit size, location, amount that the unit if outside of the target or bandwidth. If the TOP does not specify a timing portion (i.e., duration when notification required) to its notification requirements in Part 5.2 (e.g., outside range for 5 minutes), there can be a lack of clarity of the notification requirements for the Generator Operator. Specifying the timing portion within the notification requirements while maintaining the necessary flexibility is recommended.

VAR-001-4.1, Requirement R5 does not include the Reliability Coordinator (RC) as a recipient of voltage or Reactive Power schedules. In Requirement R1, Part 1.1, the TOP must provide the system voltage schedule to the RC within 30 days of a request. If there is a reliability need for the TOP to provide the RC with the voltage and Reactive Power Schedule when notifying the Generator Operator, Requirement R5 should include how the RC obtains the voltage and Reactive Power schedule.

[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

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:

    1.) The Western Electricity Coordinating Council (WECC) region should consider whether VAR-002-WECC-2 (*Automatic Voltage Regulators (AVR)*) should be retired in light of the most recent versions of VAR-001-4.1 and VAR-002-4 which require all AVRs to be in service and in voltage control mode unless exempted by the TOP based on identified criteria.

    2.) In VAR-001-4.1, Requirement R5 has no requirement to identify the "initial" status of the PSS. However, VAR-002-4 Requirement R3 requires the Generator Operator to notify the Transmission Operator of a power system stabilizer (PSS) status change. The initial status of the PSS should be clarified within the notification required by Requirement R5. The status of the PSS raises the question whether any of the VAR-501-WECC-2 (*Power System Stabilizer*), or any subsequent new version, PSS requirements should be established similar to AVR requirements for inclusion of the continent-wide standards.

    3.) The WECC variance E.A.18 is specific to external control loops to the manufacturer's AVR control loop. Due to the system configuration of the WECC, it was one of the earlier adopters of AVR and PSS controls. Due to the age of the controls or difficulty with setting reactive droop compensation on some older style controls, external loop controls were implemented from the plant control system. This can be done via DCS or SCADA. Variance E.A.18 requires that if external controls are used, that they do not affect the AVR's transient response during fault conditions.
    There is a need to determine if this type of control is used outside of the WECC. Adding this variance to the continent wide NERC standard might be justified if other utilities practice this method of voltage control and there have been documented cases that the external control hindered the AVR from responding properly during a fault event.[7]

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

[7] See also (http://www.nerc.com/pa/rrm/ea/Lessons%20Learned%20Document%20Library/LL20150602_Generator_Distributed_Control_System_Impact_on_Automatic_Voltage_Regulators.pdf)

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, or 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 SC.

Preliminary Recommendation (to be completed by the Review Team after its review and prior to posting the results of the review for industry comment):

☐ RE-AFFIRM *(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 retirement 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)*:

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the Review Team after it has reviewed industry comments on the preliminary recommendation):

☐ RE-AFFIRM *(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 retirement 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)*:

Date submitted to Standards Committee:

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.[8] 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.

[8] 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

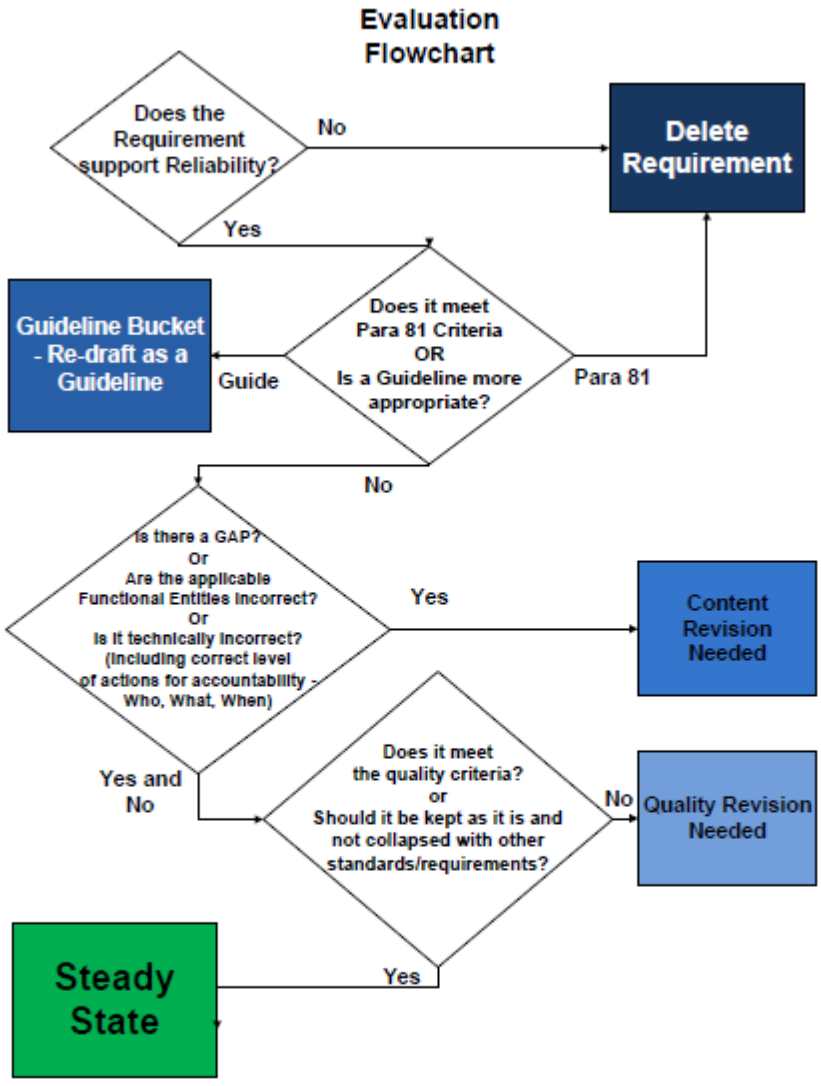

Figure 1: Evaluation Flow Chart

Attachment 4: Potential Errata Revisions/Corrections

The periodic review team has consolidated a number of errata and minor errors that could be cleaned up by a drafting team should the standard be opened for revision. If providing comment during the posting period, please reference comments with the observation number.

1. Paragraph 81 (None)
2. Clarity

   2.1. There is a grammatical error in the first sentence of VAR-001, Requirement R4 in which the word "from:" should be moved after the"1) following…" to read "1) from following…" as shown below:
   ***R4**. The Transmission Operator shall specify the criteria that will exempt generators **~~from~~**: 1) **from** following a voltage or Reactive Power schedule, 2) from having its automatic voltage regulator (AVR) in service or from being in voltage control mode, or 3) from having to make any associated notifications.*

   2.2. Insert the word "calendar" between "30 days" for VAR-001-4.1, Requirement R5, Part 5.3 to be consistent with other uses within the standard and the Measure.

   2.3. Measure M1 should use the term “calendar” like the requirement.

   2.4. Measure M5 uses the capitalized term "Reactive Power Schedule" that is not a glossary term. "Reactive Power" is a defined term. Lowercase the word "schedule."

   2.5. Requirement E.A.18 (i.e., WECC Variance) uses the capitalized term "Automatic Voltage Regulators" that is not a glossary term. Lowercase the capitalized term "Automatic Voltage Regulators."

   2.6. The Guidelines and Technical Basis, Rationale for R1, section should lowercase the capitalized term "Voltage Stability Ratings," a carryover from the old System Operating Limit (SOL) defined glossary term. If still in progress, coordinate with Project 2015-09 (Establish and Communicate System Operating Limits) SDT concerning the use of this term in the defined SOL term which may be changing.

   2.7. The Guidelines and Technical Basis, Rationale for R1 section should lowercase the capitalized term "post-Contingency Voltage Limits" a carryover from the old System Operating Limit (SOL) definition, the "Voltage Limits" portion should be lowercase. "Contingency" is a defined glossary term. If still in progress, coordinate with Project 2015-09 (*Establish and Communicate System Operating Limits*) SDT concerning the use of this term in the defined SOL term, which may be changing.

2.8. The Guidelines and Technical Basis, Rationale for R5 section, if retained, use lowercase "Voltage Schedule" because it is not a defined glossary term. If defined in the future, ensure consistency within the standard.

2.9. Use the format of "Mvar" rather than “MVAR” for Mega-voltampere reactive to be consistent with the IEEE designation throughout VAR-001. Spell out the first occurrence.

2.10. VAR-001-4.1, Requirement R6 should have the term “necessary” removed as it is superfluous.

3. Definitions (None)

4. Compliance Elements

4.1. Requirement R1 incorrectly states the Time Horizon of "Operational Planning" and it should be "Operations Planning." Correct this inconsistency in the Requirement and Table of Compliance Elements (i.e., VSL).

4.2. Requirement R2 incorrectly states the Time Horizon of "Operational Planning" and it should be "Operations Planning." Correct this inconsistency in the Requirement and Table of Compliance Elements (i.e., VSL).

4.3. Requirement R3 incorrectly states the Time Horizon of "Operational Planning" and it should be "Operations Planning." Correct this inconsistency in the Requirement and Table of Compliance Elements (i.e., VSL).

4.4. Requirement R3 Time Horizons[9] of Same-day Operations and Operational Planning are inappropriate. The requirement states "shall operate or direct the Real-time operation of devices", which would imply a Time Horizon of “Real-time Operations.” Therefore, replace the time horizons of Same-day Operations and Operational Planning with “Real-time Operations.”

4.5. Measure M2 incorrectly states the Time Horizon of “Operational Planning” and it should be “Operations Planning.” Correct this inconsistency.

4.6. Measure M3 has “may include,” but not the full phrase “may include, but is not limited to…” Add the additional verbiage for completeness.

4.7. The sentence construction of VAR-001-4.1 Measure M4 is incorrect and should be updated for correctness. The word “from:” should be moved to “1) from following…”

5. Consistency with other Reliability Standards (None)

6. Changes Technology, System Conditions, or other Factors (None)

[9] Time Horizons are used as a factor in determining the size of a sanction. If an entity violates a requirement and there is no time to mitigate the violation because the requirement takes place in real-time, then the sanction associated with the violation is higher than it would be for violation of a requirement that could be mitigated over a longer period of time. http://www.nerc.com/files/Time_Horizons.pdf

7. Practicable (None)
8. Consideration of Generator and Transmission Interconnection Facilities (None)
9. Results-Based Standard (RBS) (None)
10. Technical accuracy (None)
11. Functional Model (None)
12. Applicability (None)
13. Reliability Gaps (None)
14. Technical Quality (None)
15. Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)
16. Related Regional Reliability Standards (None)

Attachment 5: Other Miscellaneous Corrections / Revisions

The periodic review team has consolidated a number of observations here that could be considered by a drafting team should the standard be opened for revision. If providing comment during the posting period, please reference comments with the observation number.

1. Paragraph 81

   1.1. The second part of VAR-001-4.1, Requirement R5, Part 5.1 (i.e., "*and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage*).") appears redundant with VAR-002-4, Requirement R1 and could be retired.

   Background: The periodic review team recognizes that an automatic voltage regulator or "AVR" has several different operating modes, one being constant voltage, and another being constant reactive output. The requirement to operate with the AVR in the automatic mode is the driver of the requirement. The Transmission Operator should have flexibility to direct either voltage or reactive control at a specified voltage point (i.e., AVR in automatic). This issue would go away if the second part of VAR-001-4.1, Requirement R5.1 (i.e., "*and direct the Generator Operator to comply with the schedule in automatic voltage control mode (the AVR is in service and controlling voltage).*") is removed from VAR-001-4.1, Requirement R5.1.

2. Clarity

   2.1. VAR-001-4.1, Requirement R6 implies the consultation is a performance of the requirement (see Measure M6) due to the construction of the Requirement leading off with “After consultation with the Generator Owner…”. Re-structure the Requirement to show the consultation a part of the performance to align with the Measures “…and that it consulted with the Generator Owner” or another equally effective option to eliminate the ambiguity.

   2.2. VAR-001-4.1, Requirement R4 does not provide clarity on how the exemption criteria developed (e.g., blanket or specific). This applies to the voltage schedule and/or Reactive Power schedule in VAR-001, Requirement R5. Additional clarity on how the exemption criteria is developed in Requirement R4 could be helpful. For example, whether it is a blanket exemption or specific to certain generating units. Additionally, if a Generator Operator is unable to meet its voltage schedule, how would an exemption be applied where a small generator is trying to control voltage when another large generator is driving Mvar flow? How would this work in the case where the Transmission Operator has determined that there will be no criteria for exemption under Requirement R4?

2.3. Some entities are evaluating dynamic voltage schedules developed in the next-day or Real-time environment. As written the standard provides a Transmission Operator the flexibility to develop a voltage schedule that encompasses whatever time period and operating parameters that are appropriate. If VAR-001-4.1, Requirement R5 is revised in the future, edits should preserve the flexibility to allow for specifying the schedule in both Real-time and day-ahead.

2.4. When implementing a voltage schedule, the Transmission Operator needs to coordinate and be cognizant of the system response due to a change of any generator's voltage schedule. VAR-001-4.1, Requirement R5 should consider additional clarity (could be addressed in the Guidelines and Technical Basis section) around coordination of implementing the voltage schedules so that they are not all implemented at the same point in time (e.g., seasonal, time of day based, Voltage schedules for multiple generators).

2.5. There is inconsistency between VAR-001-4.1, Requirement R1 and Requirement R5 to clarify that the system voltage schedule in Requirement R1 may be the same schedule or at the same points in the system as that of Requirement R5, where one "schedule" may be derived and used for both requirements (e.g., The "system" schedule may be identified to be at the high-side of the generator step-up unit transformers only). Requirement R5 uses "voltage schedule" and "Reactive Power schedule," but only [system] voltage schedule is used in Requirement R1. Consider the need to include "Reactive Power schedule" in Requirement R1. The language should also retain flexibility so that Requirement R1 can be the same or different points in the system as Requirement R5.

3. Definitions

3.1. Defining the following terms "generator voltage schedule" and "generator Reactive Power schedule, "system voltage schedule," and "automatic voltage regulator (AVR)" (could be technology specific) may improve clarity. If so, review the Reliability Guideline: "Reactive Power Planning" section to determine if the Application Guideline in the standard provides clarity or at a minimum is consistent with the Reliability Guideline.

4. Compliance Elements

4.1. Measure M2 uses "resources based on their assessments of the system" as a measure for performance not required by the requirement. The clause "based on their assessments of the system" should be removed from the measure or added to the requirement to be consistent.

4.2. Measure M2: "For the operational planning time horizon, Transmission Operators shall have evidence of assessments used as the basis for how resources were scheduled" is all inclusive. Reword the measure to conform to the requirement. For example, evidence may include…".

4.3. Measure M3 does not include "or direct" in the language. Revise the Measure to be consistent (i.e., direct or instruct, if changed according to other recommendations herein).

4.4. Section C1.2, Evidence Retention is silent on the Generator Operator (within the WECC Region), which is an applicable functional entity in the standard. The evidence retention section should provide minimum periods for all applicable entities listed in the standard.

4.5. The VSL in Requirement R5 does not make the distinction (e.g., High uses "all" and Severe use "any") as to the number of missed notifications, but the Measure M5 uses "applicable" which gives guidance that the requirement is implicitly not including exempt Generator Operators.

4.6. The second portion of the Severe VSL for Requirement R5 VSL language may need a High VSL component to address the notification component of the requirement for deviations.

4.7. The VSL for Requirement R5 needs to replace “does” (present tense) with “did” (past tense). VSLs are based on what happened in the past.

4.8. Requirement R4 may need to include Real-time Operations Time Horizon. It is practical that this exemption could be issued in Real-time.

4.9. Some entities are evaluating dynamic voltage schedules developed in the next-day or Real-time environment. If implementing Real-time or close to Real-time voltage scheduling a Transmission Operator would need to provide the required clarity. VAR-001-4.1 Requirement R5 may need to include the Real-time Operation Time Horizon.

5. Consistency with other Reliability Standards

5.1. VAR-001-4.1, Requirement R1 should include an additional clarifier to "adjacent" such as "within an Interconnection" or similar which could add clarity that voltage schedules for asynchronously adjacent Transmission Operators across a DC tie do not need to provide voltage schedules to one another. Voltage output on each side of the DC tie is controlled by the DC tie operator (e.g., language in COM-001-2).

5.2. Requirements R3 and R5.1 use the term “instruct” in lieu of “direct” to align more closely with more recent changes in IRO/TOP/COM standards which replaced the term “directive” with “Operating Instruction.”

5.3. There are cases, primarily for non-U.S. entities, for which the Transmission Owner (TO) owns the generator step-up (GSU) transformer. Requirement R6 properly identifies the Generator Owner functional entity, but does not include the TO that owns the GSU transformer. The requirement should include the TO in order to address those cases where the TO owns GSUs transformer.

6. Changes Technology, System Conditions, or other Factors (None)

7. Practicable (None)

8. Consideration of Generator and Transmission Interconnection Facilities (None)

9. Results-Based Standard (RBS)

9.1. Requirement R6 is not results-based and should be evaluated whether it can be restructured. For example, the requirement lists “how” to accomplish the goal of providing tap changes to the Generator Owner rather the specifically identifying “what” is required by the Transmission Operator (See also Attachment 6, Item 2.1).

10. Technical accuracy (None)
11. Functional Model (None)
12. Applicability (None)
13. Reliability Gaps (None)
14. Technical Quality (None)
15. Does the Reliability Standard reflect a higher solution than the lowest common denominator? (None)
16. Related Regional Reliability Standards (None)

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.

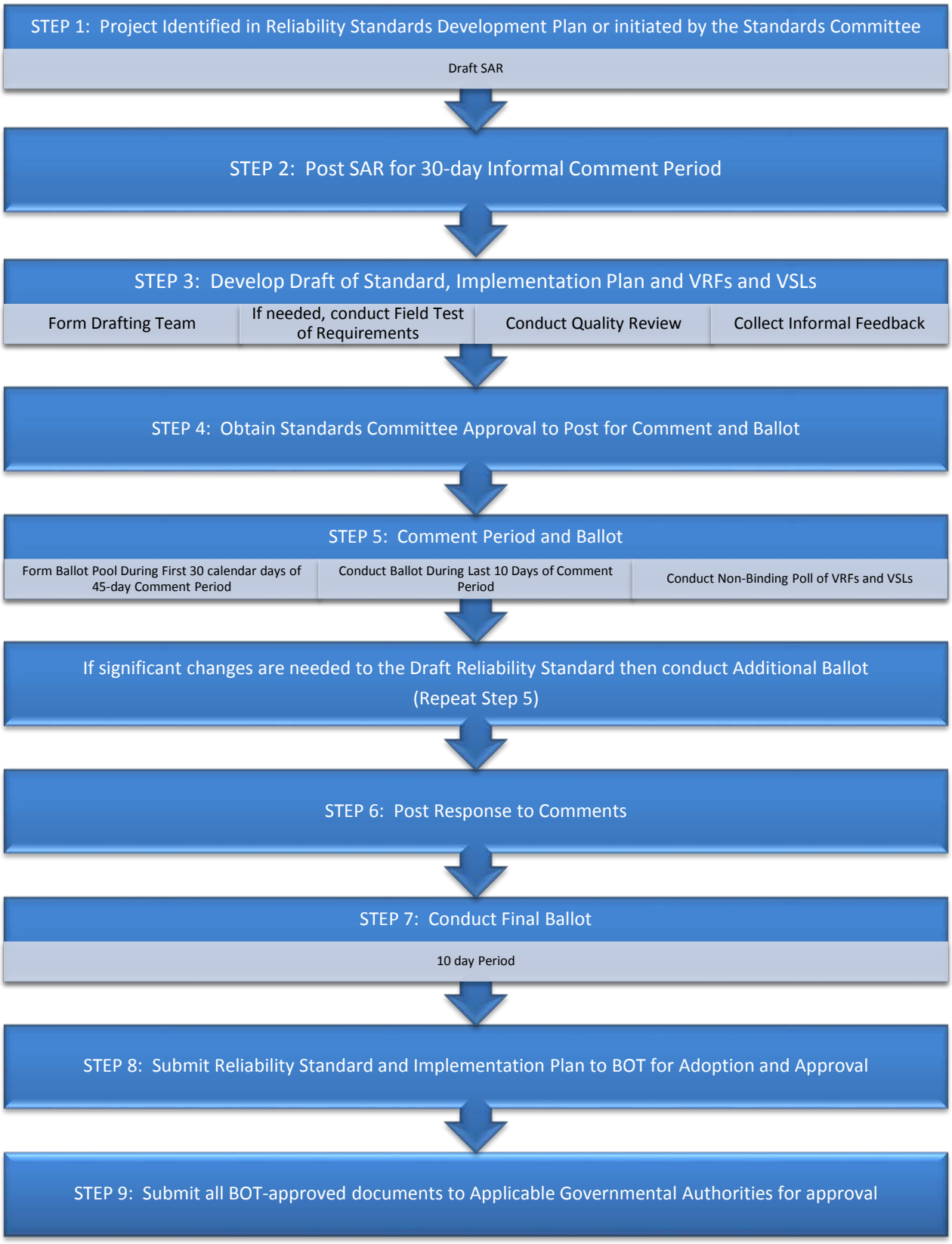


FIGURE 1: Process for Developing or Modifying a Reliability Standard

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.

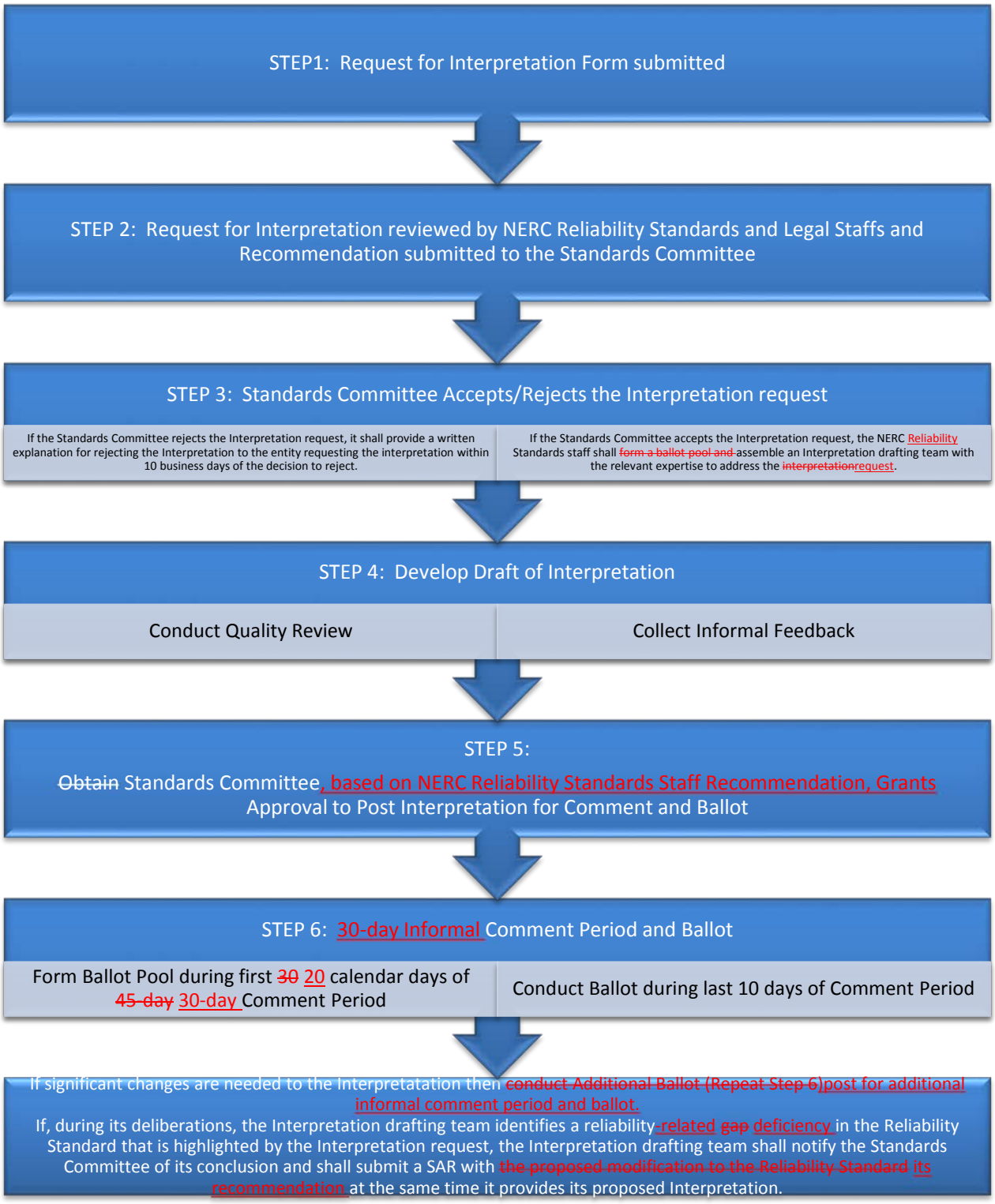
If, during its deliberations, the Interpretation drafting team identifies a reliability-related ~~gap~~ deficiency in the Reliability Standard that is highlighted by the Interpretation request, the Interpretation drafting team shall notify the Standards Committee of its conclusion and may submit a SAR 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.

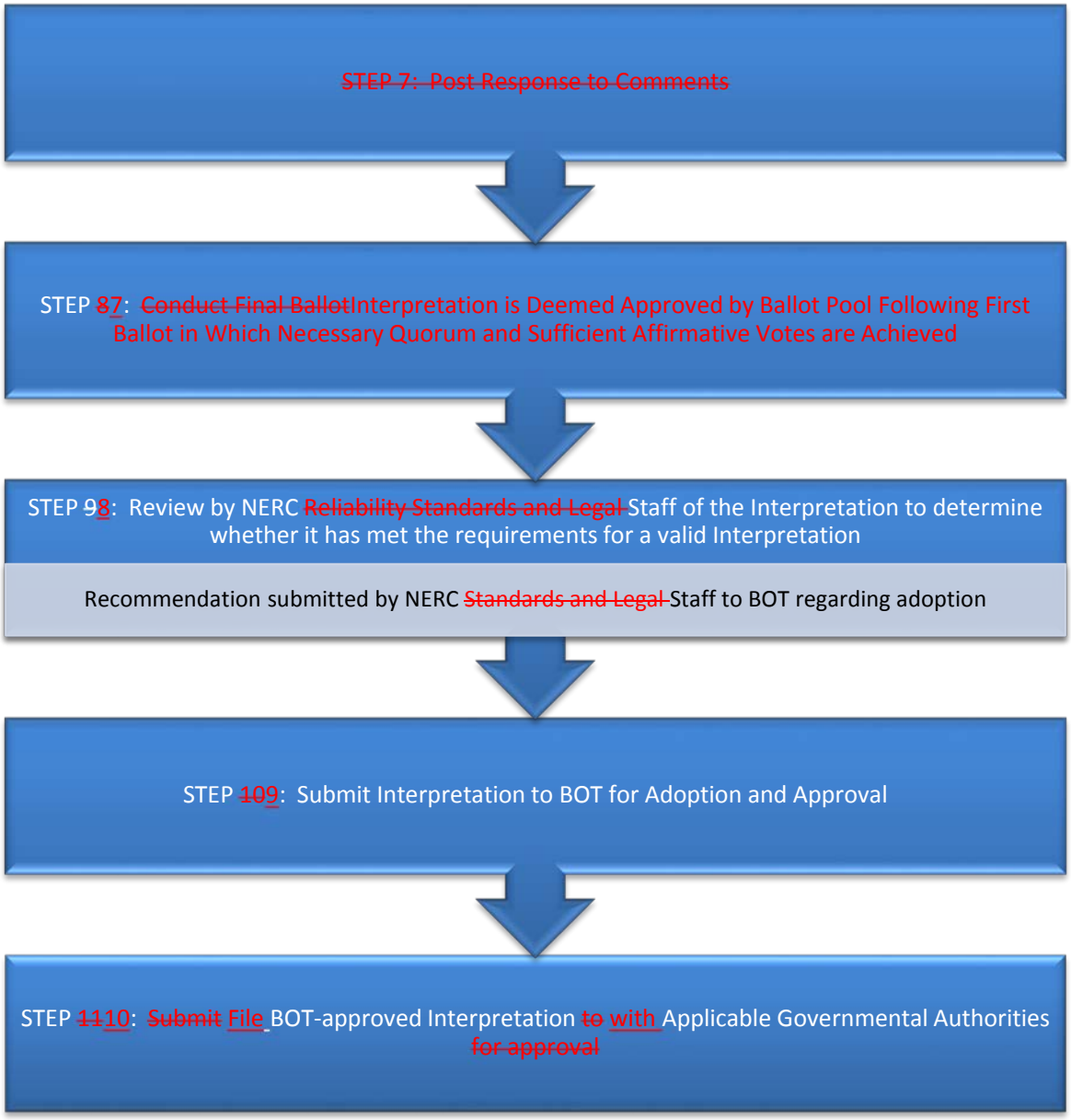


FIGURE 2: Process for Developing an Interpretation

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

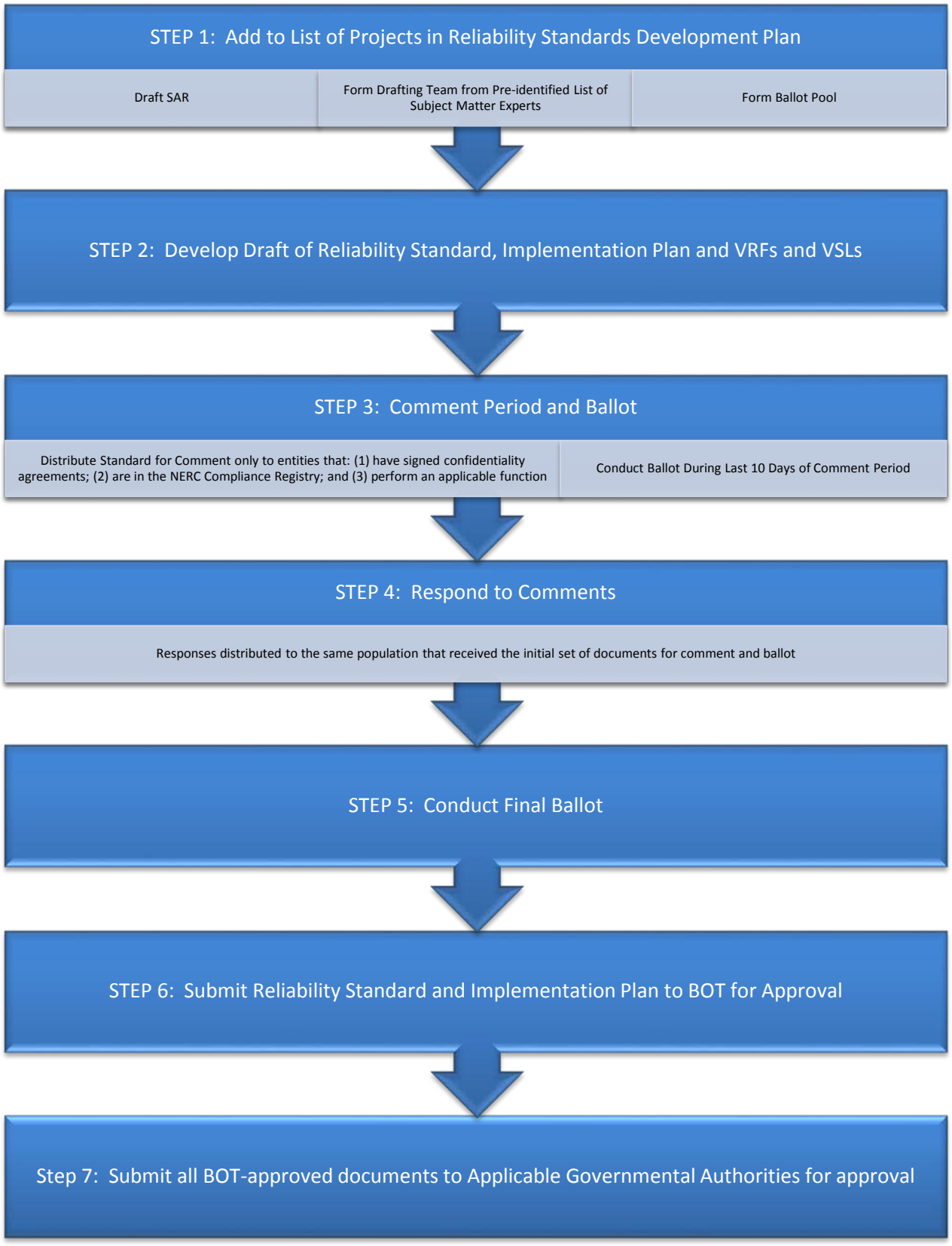


FIGURE 3: Process for Developing a Standard Responsive to an Imminent, Confidential Issue

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

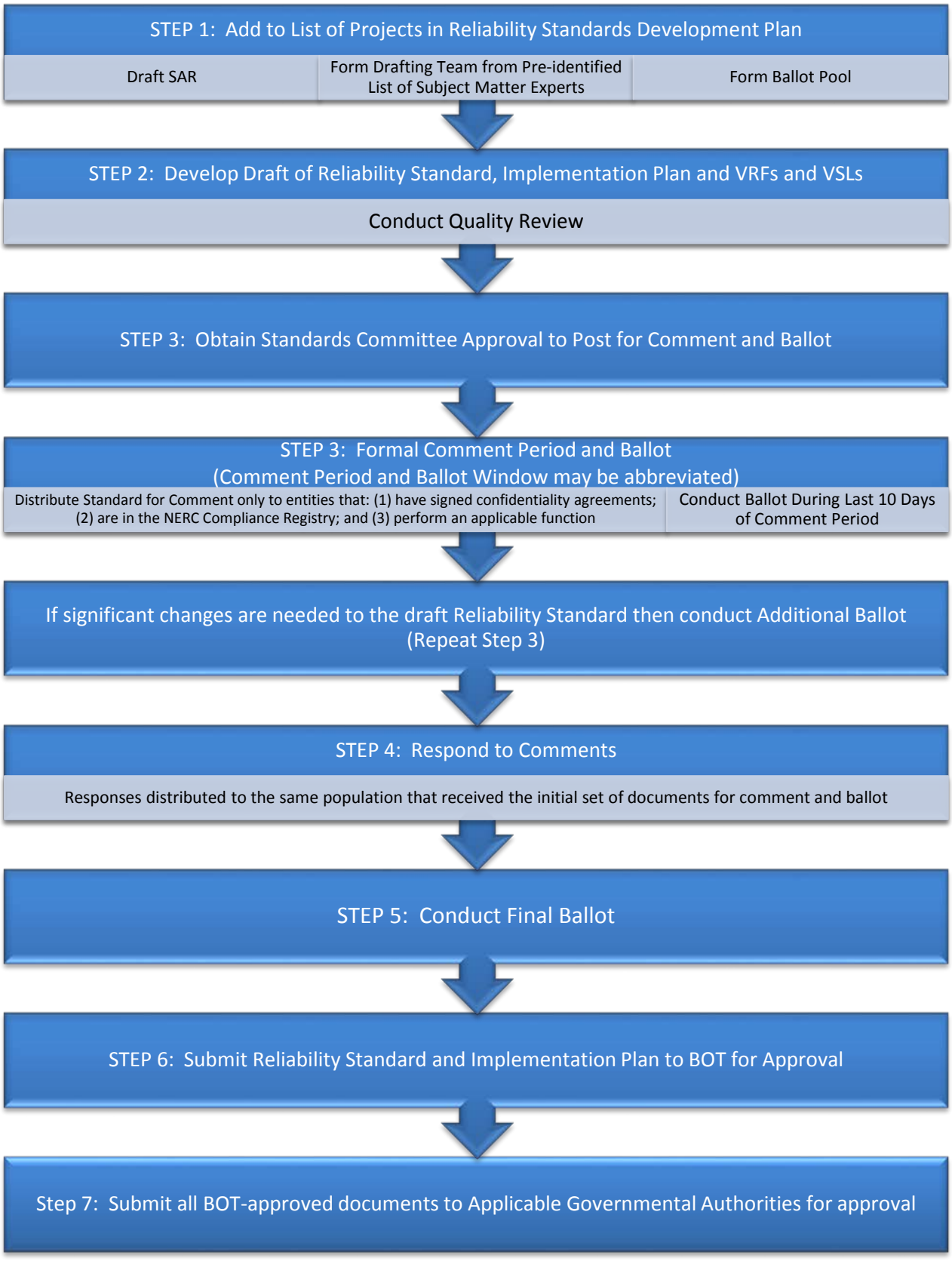


FIGURE 4: Developing a Standard Responsive to a Non-Imminent, Confidential Issue

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.

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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.

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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):

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)*:

Date submitted to Standards Committee:

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

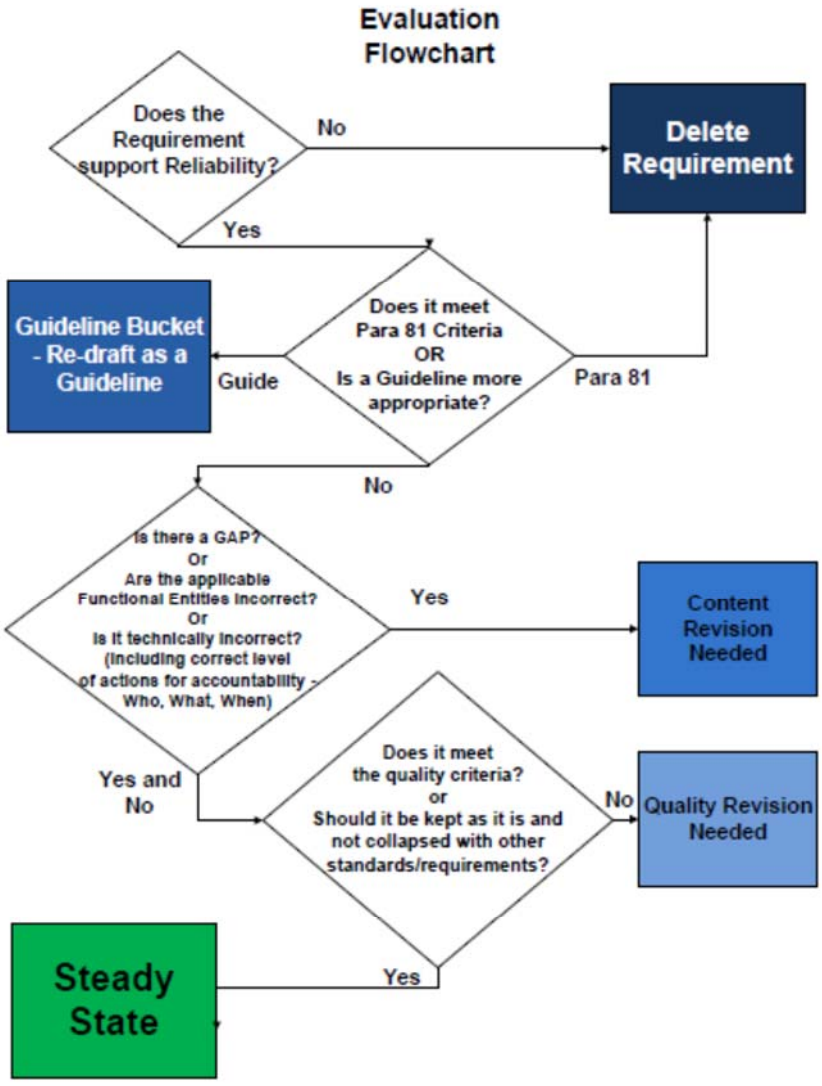

Figure 1: Evaluation Flow Chart

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):

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)*:

Date submitted to Standards Committee:

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

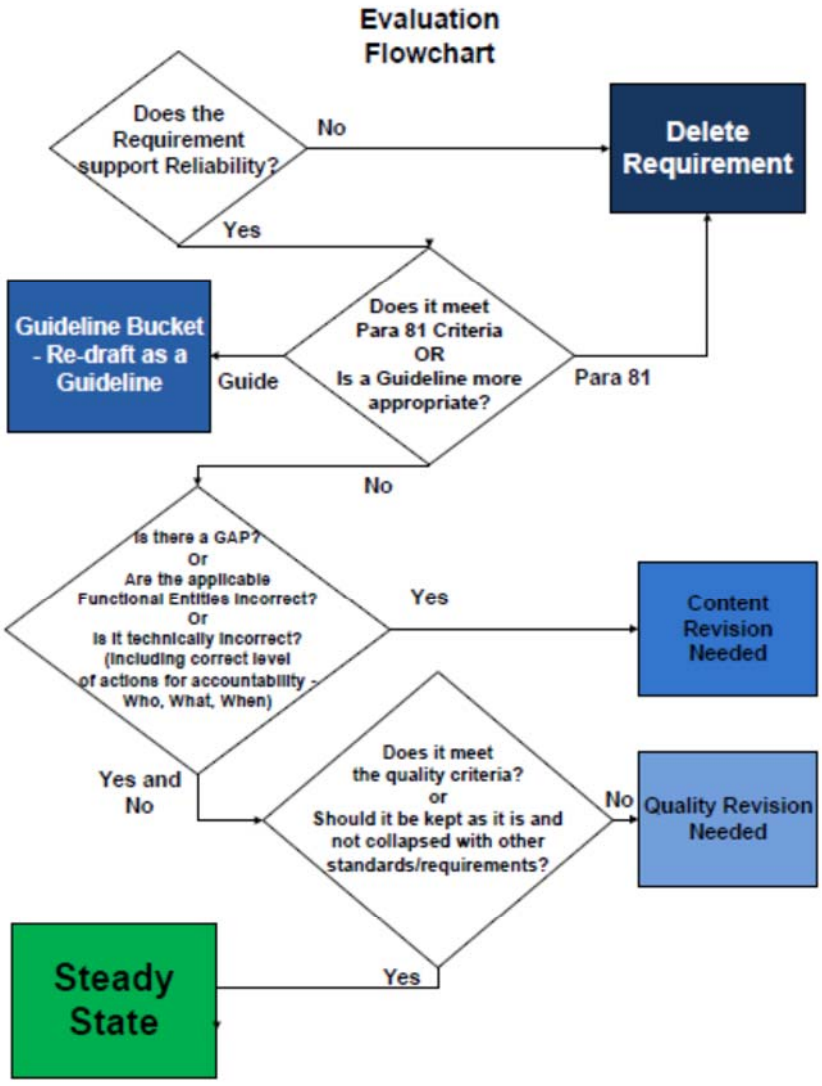

Figure 1: Evaluation Flow Chart

New or Modified Term(s) Used in NERC Reliability Standards

Glossary Term(s):

System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations. ~~The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:~~

- ~~Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings)~~
- ~~transient stability ratings (applicable pre- and post- Contingency stability limits)~~
- ~~voltage stability ratings (applicable pre- and post-Contingency voltage stability)~~
- ~~system voltage limits (applicable pre- and post-Contingency voltage limits)~~

SOL Exceedance: An operating condition characterized by any of the following:

- Actual or pre-Contingency flow on a Facility is above the Normal Rating
- Calculated post-Contingency flow on a Facility is above the highest Emergency Rating
- Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs
- Actual or pre-Contingency bus voltage is outside normal System voltage limits
- Calculated post-Contingency bus voltage is outside the emergency system voltage limits
- Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs
- Operating parameters indicate the next Contingency could result in instability.

DRAFT

A. Introduction

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

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

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:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.

R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable 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.

R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall:

3.1. Require that System voltage limits are not outside of the Facility voltage ratings;

3.2. Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements;

3.3. Require that System voltage limits are above 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; and,

3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.

R4. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the stability limitations to be used in operations. The method shall:

4.1. Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following:

4.1.1. steady-state voltage stability;

4.1.2. transient voltage response;

4.1.3. angular stability; and

4.1.4. System damping.

4.2. Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies:

4.2.1. Loss of one 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 of a direct current line.

4.2.2. Loss of any multiple Contingencies identified in Requirement R5.

4.3. Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch;

4.4. Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8;

4.5. Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and,

4.6. Specify how stability limitations will be established when there is an impact to more than one TOP in its Reliability Coordinator Area.

R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.

R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including:

6.1. Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation;

6.2. Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation;

6.3. Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and,

6.4. Unacceptable impacts on neighboring Reliability Coordinator Areas within an Interconnection.

R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.

R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address:

8.1. Thresholds for initiating evaluation of potential impacts;

8.2. A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and,

8.3. A review of the operating state experience for the purpose of determining whether an IROL should be established.

R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to:

9.1. Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;

9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and,

9.3. Each Transmission Operator that operates in the Reliability Coordinator Area.

DRAFT

A. Introduction

1. **Title:** Establish and Communicate System Operating Limits

2. **Number:** FAC-014-3

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

   4.1.2. Transmission Operator

   4.1.3. Planning Coordinator

   4.1.4. Transmission Planner

5. **Effective Date:** TBD

B. Requirements and Measures

R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.

R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.

R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.

R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area.

4.1. The Reliability Coordinators shall provide any updates to the SOL values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.

R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area:

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5.1. Identification of the Facilities that are critical to the derivation of the IROL;

5.2. The value of the IROL and its associated IROL T_V;

5.3. The associated Contingency(ies); and,

5.4. The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).

R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area:

6.1. Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.

R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.

R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include:

8.1. The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation);

8.2. The Contingencies which result in the instability;

8.3. 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 that was employed (or invoked) to address the instability; and,

8.4. Any Corrective Action Plan associated with the instability.

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Summary of Proposed Revisions

Project 2015-09 Establish and Communicate System Operating Limits

Do not use this form for submitting comments. Use the electronic form to submit comments on **Project 2015-09 Establish and Communicate System Operating Limits** (SOL). The electronic form must be submitted by **8 p.m. Eastern, Friday, August 12, 2016.**

Additional information is available on the project page. If you have questions, contact Lacey Ourso, Standards Developer by email or phone at 404.446.2581.

Background Information regarding Project 2015-09 Establish and Communicate System Operating Limits

The Facilities Design, Connections, and Maintenance (FAC) Reliability Standards fulfill an important reliability objective for determining and communicating System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) used in the reliable operation of the Bulk Electric System (BES). The purpose of Project 2015-09 – Establish and Communicate System Operating Limits is to revise these requirements. Revisions are necessary to eliminate overlap with approved Transmission Planning (TPL) requirements,[1] enhance consistency with Transmission Operations (TOP)[2] and Interconnection Reliability Operations (IRO)[3] standards, and address other concerns in the existing FAC standards regarding the determination and communication of SOLs and IROLs. As outlined in the Standards Authorization Request (SAR), the scope of the standards development project includes development of new or revised requirements and/or NERC Glossary definitions to provide clarity and consistency for establishing SOLs and IROLs, and to address potential reliability issues resulting from application of the current NERC Glossary definitions for SOL and IROL.[4]

High-level Overview of Proposed Revisions to FAC Reliability Standards

In developing revisions to the FAC Reliability Standards and definitions related to SOL and IROL, the standard drafting team (SDT) has focused on alignment with how SOLs and IROLs are treated in the approved TOP and IRO Reliability Standards (enforceable beginning April 1, 2017). The SDT believes this shift is critical to align the approach for how the System is actually operated as a result of the wholesale

[1] *See*, TPL-001-4
[2] *See*, TOP-001-3, TOP-002-4, TOP-003-3
[3] See, IRO-001-4, IRO-002-4, IRO-008-2, IRO-010-2, IRO-014-3, IRO-017-1
[4] The SAR was sponsored and submitted by the Project 2015-03 -Periodic Review of System Operating Limit Standards periodic review team (PRT).

revisions to the TOP and IRO Reliability Standards and reflects the manner in which operations are currently conducted. Below is a detailed explanation of how the proposed revisions complement the TOP/IRO revisions. The proposed changes to the FAC standards support a more reliable, dynamic approach to operating within actual limits that exist on the system, as opposed to reliance on "operating limits" that were set well in advance.

Overview of How Proposed Revisions Align with Revised TOP and IRO Reliability Standards

The revisions proposed to the FAC standards were designed to work together with the approved TOP and IRO Reliability Standards. The combination of the proposed revisions to the FAC standards and the TOP and IRO Reliability Standards, including the defined terms contained in those standards (Operational Planning Analysis (OPA)[5], Real-time Assessment (RTA)[6], and Operating Plans) when executed together will result in maintaining reliable BES performance. Thus, it is imperative that your review of the proposed revisions to the FAC standards is conducted with a full understanding of how these standards will work together with the approved TOP and IRO Reliability Standards. The proposed FAC revisions standing alone will not provide a complete picture of how different functional entities will work together to establish the appropriate operational limits, and then actually operate to them.

Under the approved TOP and IRO Reliability Standards:

- TOP-002-4 Requirement R1 requires the TOP to have an OPA that will allow it to assess whether its planned operations for the next day will exceed any of its SOLs.
- TOP-002-4 Requirement R2 requires that the TOP have an Operating Plan to address potential "SOL exceedances" identified as a result of its OPA.
- TOP-001-3 Requirement R13 requires that the TOP perform a RTA at least once every 30 minutes.

[5] NERC Glossary defines Operational Planning Analysis (OPA) 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.)" [NERC Glossary as of June 24, 2016]

[6] NERC Glossary defines Real-time Assessment (RTA) 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.) [NERC Glossary as of June 24, 2016]

- TOP-001-3 Requirement R14 requires that the TOP initiate its Operating Plan to mitigate an "SOL exceedance" identified as part of its Real-time monitoring or RTA.

For more information on the TOP/IRO revisions, please visit the Project 2014-03 Revisions to TOP/IRO Reliability Standards project page.

Overview of Proposed Revisions to FAC-011-3, FAC-014-2 and Defined Terms SOL and SOL Exceedance

As outlined in greater detail below, the SDT is proposing to revise the existing definition of SOL and create a new NERC Glossary definition for "SOL Exceedance." The new definitions support the conceptual distinction between operating practices and the SOL itself. The SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity operates to those SOLs can vary depending on the planning strategies, operating practices, and mechanisms employed by the entity. The revised definition of SOL and new definition of "SOL Exceedance" will work together with the future-enforceable TOP and IRO Reliability Standards, including the definitions of OPA, RTA and Operating Practices as follows:

- The TOP is required to have an OPA to assess whether its planned operations for the next day will exceed any of its SOLs (*see*, TOP-002-4, Requirement R1). If the OPA identifies potential SOL exceedances, the TOP is required to have an Operating Plan to address those potential SOL exceedances (*see*, TOP-002-4, Requirement R2).
- Additionally, the TOP is required to perform a RTA at least once every 30 minutes (*see*, TOP-001-3 Requirement R13). If the TOP identifies that an SOL is being exceeded in Real-time operations, the TOP will implement the mitigating strategies identified in its Operating Plan (*see*, TOP-001-3 Requirement R14).
- In other words, an "SOL Exceedance" is simply unacceptable system performance that must be mitigated in accordance with the action plan the TOP has laid out in its Operating Plan.
- A potential SOL Exceedance may be identified by an OPA, or an actual SOL Exceedance may be identified by an RTA.
- The Operating Plan can include specific Operating Procedures or more general Operating Processes. The TOP Operating Plans include both pre- and post- Contingency mitigation plans and strategies. The pre-Contingency strategies are implemented before the Contingency occurs to prevent the potential negative impacts on reliability of the Contingency. Post-Contingency mitigation plans and strategies are actions that the TOP will implement after the Contingency occurs to bring the system back within limits.
- The Operating Plans contain adequate details regarding the appropriate timelines to escalate the level of mitigation to ensure BES performance is maintained as required by the RC SOL Methodology.

The proposed definition of SOL Exceedance (described in further detail below) provides clarity regarding what is deemed to be "unacceptable system performance." When the conditions identified in the definition of SOL Exceedance occur, the TOP must be prepared

to implement its action plan outlined in its Operating Plan to mitigate that particular condition and return the system back within acceptable limits.

The SDT believes that the proposed definitions and revisions to the FAC standards will eliminate confusion between the operating practices used by the TOP and the actual limits themselves. The revisions provide clarity regarding (1) what the limits are, (2) what it means to exceed them, and (3) how an "SOL Exceedance" should be addressed by the TOP in operations planning (TOP-002-4 Requirement R2) and Real-time operations (TOP-001-3 Requirement R14).

Purpose of 30-day Informal Comment Period

As outlined above, the scope of Project 2015-09 includes revision of the requirements for determining and communicating SOLs and IROLs used in the reliable planning and operation of the BES. This informal 30-day posting does not encompass the entire scope of work that the SDT will undertake for the project. Rather, this is only a piece of the complete work. However, the SDT believes it to be the most critical area. The direction taken with regard to these standards set the foundation for building a proper SOL methodology to ensure that SOLs are established and communicated in a manner that will later ensure reliable BES operation when carried out in operations.

Reliability Standards and definitions that **are included** (as part of this limited, informal posting):

- FAC-011-3 – System Operating Limits Methodology for the Operations Horizon
- FAC-014-2 – Establish and Communicate System Operating Limits
- Revisions to definition of System Operating Limit (SOL)
- New definition of SOL Exceedance

Reliability Standards and definitions that **are NOT included** (as part of this limited, informal posting):

- FAC-010-3 – System Operating Limits Methodology for the Planning Horizon
- Revisions to definition of Interconnection Reliability Operating Limit (IROL)
- Necessary revisions to existing Reliability Standards to incorporate concepts included in new defined term "SOL Exceedance" (*i.e.,* TOP-002-4 – capitalize SOL Exceedance to incorporate usage of defined term).

Although this is only an informal posting, the SDT underscores the importance of this posting. The SDT believes that the revisions proposed represent a significant improvement in how the industry works together to ensure reliability by establishing SOLs and operating to them in a manner that is reflective of the changing technology, and dynamic manner where entities have the ability to assess pre- and post-

Contingency performance in Real-time based on actual operating conditions. For these reasons, the SDT requests that commenters please take the time to review the background materials from the Project 2015-09 SOL Technical Conference which outline all of the various issues that were considered by the team, and discussed in an open forum with industry members. The SDT believes that we have captured the essence of the direction that the industry would like to take, but this is the opportunity for the team to continue to improve on proposed revisions by obtaining early feedback. The SDT looks forward to hearing and understanding your perspective for each of the very specific issues and associated questions raised below. In order for the SDT to thoroughly understand and incorporate your feedback into the future standard development, please do not simply provide yes or no responses. Please provide us with your perspective. Give us as much detail as you can. If you disagree with the SDT's direction, please provide an alternative approach that you believe will be superior to the one that the SDT proposed.

Proposed Revisions, Background Information and Questions

A. Definitions

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
System Operating Limits: Reliability limits used for operations, to include Facility Ratings, System voltage limits, and stability limitations.	The current definition of SOL (and the related FAC standards) presume an operating paradigm whereby a study or analysis is performed ahead of time to establish an SOL; the SOL is then communicated to operators; and the operators are given an operating plan to operate below the SOL with the presumption that doing so will result in acceptable pre- and post-Contingency system performance in Real-time operations. However, due to changes in the TOP and IRO Reliability Standards, along with advancements in technology from the time that the FAC standards were originally drafted, this is not reflective of how the system is actually operated. Today, entities continuously assess system performance and identify potential events in Real-time, based on *actual* operating conditions. The proposed revisions to the SOL definition, coupled with the proposed new definition of SOL Exceedance (see below) and the revisions to the FAC standards will support the concept that the SOL is the actual operating parameter; and eliminate confusion between "what the limits are" verses "how the system should be operated given the limits."	Existing definition of SOL: "The value (such as MW, Mvar, amperes, frequency or volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (applicable pre- and post-Contingency Equipment Ratings or Facility Ratings) • transient stability ratings (applicable pre- and post-Contingency stability limits) • voltage stability ratings (applicable pre- and post-Contingency voltage stability)

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	Given this shift, there is no need for the existing SOL definition language that includes concepts of "the most limiting criteria," "specified system configuration," "operation within acceptable reliability criteria," and "pre- and post-Contingency." These concepts are covered in the future-enforceable TOP and IRO Reliability Standards (including the defined terms contained therein: OPA, RTA, and Operating Plans), along with the proposed revisions to the FAC standards. As a result of the proposed revisions, the Facility Ratings, System voltage limits, and stability limitations are SOLs, all of the time, regardless of which one is "the most limiting." Also, as detailed below, the definition of "SOL Exceedance" will complement the revised definition of SOL by specifically identifying operating conditions that are deemed unacceptable, and require action by the TOP to mitigate. The proposed revisions use the term "stability limitation" rather than "transient stability limit," "voltage stability limit" or the Glossary term "Stability Limit." The intent of the SDT is that "stability limitation" is intentionally broad and can be used to encompass a number of different types of stability-related limitations or phenomenon, including, but not limited to, weighted short-circuit ratio (WSCR), sub-synchronous resonance (SSR), phase angle limitations, fault-interrupting capability of breakers, transient voltage limitations on equipment, and geomagnetic-induced currents on equipment. The Glossary term "Stability Limits" is not appropriate because it is limited to the maximum power flow value; this is too restrictive and not technology-neutral, as tools allow entities	• system voltage limits (applicable pre- and post-Contingency voltage limits)"

Proposed Revisions to Definition of System Operating Limits (SOL)		
Proposed Revised Definition	**Explanation of Proposed Revision**	**Relevant Definition(s) or Standards Impacted By Proposed Revision**
	to monitor and control parameters other than maximum power flow values in order to demonstrate reliable stability performance. For more information regarding the proposed revisions to the SOL definition (and the definition of SOL Exceedance), please reference the Project 2014-03 – TOP and IRO Reliability Standards white paper entitled, "System Operating Limit Definition and Exceedance Clarification."	

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
SOL Exceedance: An operating condition characterized by any of the following: • Actual or pre-Contingency flow on a Facility is above the Normal Rating; • Calculated post-Contingency flow on a Facility is above the highest Emergency Rating;	As explained above, under the proposed revisions, the SOL is the actual set of Facility Ratings, System voltage limits, or stability limitations that are to be monitored for the pre- and post-Contingency state. How an entity remains within those SOLs will vary depending upon the particular Operating Plan of the entity. When the operating conditions listed in the definition of SOL Exceedance are identified – through an OPA or RTA – the TOP will take the actions outlined in its Operating Plan to mitigate the condition. The SDT did not include specific timing requirements for each condition listed in the definition, because the appropriate timing for operator response can vary depending upon the particular facts and	**Mapping to existing FAC standards or definitions under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- Identifies performance requirements that RC SOL Methodology shall include. If the definition of SOL Exceedance is pursued by the SDT, the definition would be incorporated into existing standards that currently rely on the concept of an

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
• Calculated post-Contingency flow on a Facility is above a Facility Rating for which there is not sufficient time to reduce the flow to acceptable levels should the Contingency occurs; • Actual or pre-Contingency bus voltage is outside normal System voltage limits; • Calculated post-Contingency bus voltage is outside the emergency system voltage limits; • Calculated post-Contingency bus voltage is outside emergency system voltage limits for which there is not sufficient time to relieve the condition should the Contingency occurs; or, • Operating parameters indicate the next Contingency could result in instability.	circumstances. However, it is expected (and required) that the TOP Operating Plan specifically identify the allowable response time, along with the specific actions to be taken by the operator, in mitigating the condition. The bulleted items carry forward the types of limitations that are identified in the current definition of SOL, and incorporate the concepts of acceptable/unacceptable system performance, as currently contained in FAC-011-3 Requirement R2. For bullet item 3: This operating condition exists when the calculated post-Contingency flow falls below the highest Emergency Rating; however, the flow remains at a level where there is not sufficient time to reduce the flow to an acceptable level after the Contingency occurs. In this operating condition, the operator would be required to take pre-Contingency action, and could not rely on a post-Contingency mitigation plan. Because pre-Contingency action is required, the condition is deemed to be an "SOL Exceedance." For bullet items 4 and 5: Normal and emergency System voltage limits must respect the voltage limitations specified in the TO or GO Facility Ratings methodology (pursuant to FAC-008-3). Normal voltage limits are typically applicable for the pre-Contingency state, while emergency voltage limits are applicable for the post-Contingency state. "SOL Exceedance" with respect to these voltage	"SOL exceedance." The intent is not to change the meaning of the existing standards, rather the SDT believes that the proposed definition captures the existing meaning, but simply provides greater clarity through listing the specific types of conditions in the "SOL Exceedance" definition. In concert with proposing the new "SOL Exceedance" definition, the SDT would propose revisions (only as necessary) to existing standards to incorporate the newly defined Glossary term. Below are a few examples, but are not intended to represent a comprehensive or complete listing: • 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 result in an SOL Exceedance of its System Operating Limits (SOLs).

Proposed New Definition of SOL Exceedance		
Proposed New Definition	**Explanation of Proposed New Definition**	**Relevant Definition(s) or Standards Impacted By Proposed New Definition**
	limits occurs when either actual bus voltage is outside acceptable pre-Contingency (normal) bus voltage limits, or when Real-time Assessments indicate that bus voltages are expected to fall outside acceptable emergency limits in response to a Contingency event. Real-time Assessments recognize whether auto-reactive devices are sufficient for maintaining voltage within acceptable limits pre- or post-Contingency.	• 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) Exceedance(s) identified as a result of its Operational Planning Analysis as required in Requirement R1. • TOP-001-3 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.

B. Proposed Revisions to FAC-011-3

Proposed Reliability Standard: FAC-011-4, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall have a methodology for establishing SOLs ("SOL Methodology") within its Reliability Coordinator Area.	As outlined above, the SDT has incorporated the concepts contained in the existing FAC-011-3 Requirement R1 into the proposed revisions to the definitions of SOL and SOL Exceedance, along with the proposed revisions to FAC-011 and FAC-14. The existing Parts 1.1 through 1.3 are incorporated into the proposed new requirements, as detailed below.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – Sentence 1.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable Facility Ratings to be used in operations. The method shall address the use of common Facility Ratings between the Reliability Coordinator and	Under FAC-008-3, Facility Ratings are established by Facility owners (TOs and GOs) consistent with the owner's methodology. These Facility Ratings are communicated to the RCs and TOPs. RCs and TOPs incorporate these ratings into their tools and processes and use the ratings in establishing their SOLs. Because TOs and GOs are not required to use any sort of continent-wide methodology for establishing the Facility	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 Requirements R1, R2 and R3– GOs and TOs are required to have a methodology for developing Facility Ratings. • FAC-008-3 Requirement R6– GOs and TOs shall establish Facility Ratings consistent with its methodology.

Proposed Reliability Standard: FAC-011-4, Requirement R2		
Proposed New/Revised Requirement	**Explanation / Rationale for Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
the Transmission Operators in its Reliability Coordinator Area.	Ratings, it is possible for owners to use varying/different methodologies. This can create problems in establishing the appropriate SOL because the variations in Facility Rating methodologies may result in different or inconsistent types of Facility Ratings used in operations. If the RCs and TOPs are using different sets of Facility Ratings in conducting their respective outage coordination studies, OPAs, and RTAs, this may create a potential risk to reliability. The intent of Requirement R2 is for the RC SOL Methodology to identify the method that its TOPs will use in determining which of the Facility Ratings provided by the owner (under FAC-008-3) are appropriate for use in establishing SOLs for use in operations. As outlined above, under the revised definition of SOL, the Facility Ratings will be the SOL. The second sentence of Requirement R2 is intended to ensure that the RC and the TOP are using the same Facility Ratings, which will eliminate the risk identified above.	• FAC-008-3 Requirements R7 and R8– must provide their Facility Ratings to the RC, TOP and other functional entities. **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2)- RC SOL Methodology shall include requirement that SOLs provide BES performance, and following certain prescribed conditions/states, remain within their Facility Ratings.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall include in its SOL Methodology the method for Transmission Operators to determine the applicable steady-state System voltage limits to be used in operations. The method shall: **3.1.** Require that System voltage limits are not outside of the Facility voltage ratings; **3.2.** Require that System voltage limits are not outside of voltage limits identified in Nuclear Plant Interface Requirements; **3.3.** Require that System voltage limits are above 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; and,	There is no Reliability Standard that specifically requires establishment and communication of System voltage limits; however, System voltage limits are used in the definition of SOL and are an important aspect of reliable operations. The SDT believes it is important for the Reliability Standards to assign responsibility for the establishment and communication of System voltage limits. Like Facility Ratings, System voltage limits should be consistent between TOPs and RCs throughout all operations processes. The proposed Requirement R3 will result in the RC SOL Methodology requiring the TOP to determine System voltage limits for use in operations, consistent with the RC methodology.	**Background regarding existing standards *not* under revision by SDT:** • FAC-008-3 – Requires Facility Owner to establish Facility Ratings, which includes voltage ratings.[7] • VAR-001-4 Requirement R1 – The TOP specifies the system voltage schedule (which is either a range or a target value associated with a tolerance band) as part of its plan to operate within SOLs (and IROLs). **Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R2 (Parts 2.1 and 2.2) - RC SOL Methodology shall include requirement that SOLs provide BES performance with regard to certain prescribed conditions (pre-Contingency state, following certain identified single-

[7] Definition of Facility Ratings: The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.

Proposed Reliability Standard: FAC-011-4, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
3.6. Address coordination of System voltage limits between adjacent Transmission Operators in its Reliability Coordinator Area.		Contingencies) and remain within their thermal and voltage limits. [Proposed definitions of SOL and SOL Exceedance and Requirement R3 carry this forward.] • FAC-011-3 Requirement R1- RC SOL Methodology must state that SOLs shall not exceed associated Facility Ratings. [Proposed Part 3.1 carries this forward.] • Parts 3.2-3.6 were not clearly identified in the previous FAC standards; these are "new" requirements added by the SDT to provide clarity regarding steady-state system voltage limits.

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall include in its SOL Methodology the method for	As detailed above, the existing definition of SOL provides that the SOL is "based upon" certain criteria, including transient stability ratings. The proposed	**Background regarding existing standards *not* under revision by SDT:**

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
determining the stability limitations to be used in operations. The method shall: **4.1.** Specify stability performance criteria for single Contingencies and for multiple Contingencies (as identified in Requirement R5), including any margins applied. The criteria shall consider the following: **4.1.1.** steady-state voltage stability; **4.1.2.** transient voltage response; **4.1.3.** angular stability; and, **4.1.4.** System damping. **4.2.** Require that stability limitations are established to meet the BES performance criteria specified in Part 4.1 for the following Contingencies: **4.2.1.** Loss of one of the following either by single phase or three phase Fault to ground with normal clearing, or without a Fault: • generator;	revisions to the SOL definition make clear that the SOLs "are" the reliability limits, which include stability limitations. Additionally, under the current standards, there are no set continent-wide stability limitations criteria for use in determining SOLs. Under existing FAC-011-3 Requirement R2, the RC has flexibility with regard to establishing stability limitations; provided the system performance requirements in the standard are met. While the existing language in Requirement R2 (and portions of Requirement R3) do provide some "continent-wide" uniformity, the requirements do not provide sufficient clarity regarding the distinction between establishing stability limitations and acceptable system performance requirements/response. The proposed revisions continue to allow the RC to have flexibility in its SOL Methodology for developing stability limitations. This ensures the RC is able to appropriately tailor the methodology to meet the particular needs of its system, since a "one size fits all" approach is not appropriate for stability limitations. However, the proposed requirement does set a number of minimum	• IRO-005-3.1a, Requirement R1 (Parts 1.2 and 1.3) – Each RC should monitor its RC Area parameters, including pre and post contingent element stability conditions. • IRO-008-2, Requirement R1 – Each RC shall perform an OPA that will assess whether next day planned operations will exceed SOLs or IROLs within its Wide-area. • MOD-001-2, Requirement R1 (Part 1.1) – Each TOP that calculates TFC or TTC shall have a written methodology that describes how those values are calculated, including the pre- and post-Contingency limitations for transient and voltage stability limits and other SOLs. **Mapping to existing FAC standards under revision:** • FAC-014-2, Requirement R6 (Parts 6.1 and 6.2) – Planning Authority shall provide multiple contingencies causing stability limits, and the limits, to the

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
• Transmission circuit; • transformer; • shunt device; • single pole of a direct current line. **4.2.2.** Loss of any multiple Contingencies identified in Requirement R5. **4.3.** Describe how instability risks are identified, considering realistic levels of transfers, Load and generation dispatch; **4.4.** Consider the stability limitations (and corresponding multiple Contingencies) provided by the Planning Coordinator in accordance with FAC-014-3 Requirement R8; **4.5.** Include a description of the study models, including the level of detail that is required and allowed uses of Remedial Action Schemes (RAS); and, **4.6.** Specify how stability limitations will be established when there is an impact to	required attributes (specific to stability limitations) that must be contained within the RC SOL Methodology. The proposed approach by the SDT is for the RC SOL Methodology to continue to set the method for how stability limitations for its RC Area must be established. Under proposed Requirement R4, the RC SOL Methodology must: Part 4.1 - Specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied. Part 4.2 - Meet the performance criteria for certain identified Contingencies (listed in the standard). Part 4.3 - Describe how instability risks are identified. The SDT changed the existing language of "anticipated" to "realistic." (See, FAC-011-3 Part 3.6) The SDT believes "anticipated" could be broadly interpreted to mean anticipated by the planners (in planning horizon), instead of what is realistically anticipated by the operators in the operations time horizon. Part 4.4 – Incorporates concepts from the existing FAC-011-3 Part 3.3, and requires the RC to consider the	Reliability Coordinator, or note to the RC if there are none. *[Maps to proposed Part 4.4]* • FAC-011-3 Requirement R2 (Part 2.1) - *[Maps to proposed Part 4.1, with new requirement providing specific types of criteria that must be considered.]* • FAC-011-3 Requirement R2 (Part 2.2) - *[Maps to proposed Part 4.2]* • FAC-011-3 Requirement R2 (Part 3.6) - *[Maps to proposed Part 4.3]* • FAC-011-3 Requirement R3 (Parts 3.1 and 3.5) – *[Maps to proposed Part 4.5]*

Proposed Reliability Standard: FAC-011-4, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one TOP in its Reliability Coordinator Area.	stability limitations provided by the Planning Coordinator. Part 4.5 – This language combines some components of existing FAC-011-3 Parts 3.1, 4.3, and 3.5, but removes the blanket requirement for the study to include the entire RC Area. The revised language allows the RC to have flexibility to determine the appropriate study model, and required supporting details. Part 4.6 – The SDT believes that this Part will improve reliability by requiring the RC SOL Methodology to specify the appropriate manner to develop stability limitations, when those limitations impact more than one TOP in its RC Area. A companion requirement is FAC-014-3 Requirement R3, which requires the RC to determine the stability limitations when there is an impact to more than one TOP in its RC Area. (*See*, the proposed FAC-014-3 Requirement R3 for further explanation).	

Proposed Reliability Standard: FAC-011-4, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator shall include in its SOL Methodology the method for determining the multiple Contingencies used in the evaluation for potential System instability, Cascading outages or uncontrolled separation.	Currently effective Reliability Standard TOP-004-2 Requirement R3 requires the TOP operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by its RC. This requirement was retired by the TOP/IRO project because it was addressed by the new TOP-001-3 Requirements R12 and R14 (which are not limited by single or multiple contingencies) in combination with existing FAC-011-3 Part 3.3 and FAC-014-2 Requirement R6 (which work collectively to establish how multiple Contingencies are considered in IROLs and SOLs). The proposed Requirement R5 maintains the existing approach that the RC SOL Methodology shall specify the multiple Contingencies for use in establishing stability limitations and IROLs. Further, it improves upon the existing requirement by allowing the RC SOL Methodology to identify multiple Contingencies beyond those identified by the planners.	**Background regarding existing standards *not* under revision by SDT:** • TOP-001-3 Requirements R12 and R14 **Mapping to existing FAC standards under revision:** • FAC-011-3 Part 3.3 • FAC-014-2 Requirement R6

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R6. Each Reliability Coordinator shall include in its SOL Methodology the method and criteria for establishing Interconnection Reliability Operating Limits (IROLs). The criteria shall describe the severity and extent of reliability impact that warrants establishment of an IROL, including: **6.1.** Unacceptable quantity of load loss due to System instability, Cascading outages or uncontrolled separation; **6.2.** Unacceptable quantity of supply loss due to System instability, Cascading outages or uncontrolled separation; **6.3.** Unacceptable thresholds for inter-area oscillations (including acceptable damping criteria and criteria for inter-area oscillations versus intra-area oscillations); and, **6.4.** Unacceptable impacts on neighboring Reliability	Regional differences exist in the criteria for determining which subset of SOLs are IROLs. The SDT discussed the regional differences among the various RC Areas, and several similarities emerged, including: (1) loss of load criteria, (2) loss of generation criteria, (3) non-localized or uncontained instability, and (4) impact on neighboring RC Area. The SDT evaluated the potential positive and negative impacts of creating continent-wide requirements, and determined that establishing minimum criteria that must be considered as part of the RC Methodology would benefit reliability; while continuing to allow necessary flexibility. The proposed language provides greater uniformity by identifying the criteria to be considered by the RC in establishing IROLs. The criteria must describe, at a minimum, the severity and extent of what is/not allowable with regarding to: (1) loss of load, (2) quality of supply loss, (3) thresholds for inter-area oscillations, and (4) impacts on neighboring RC Areas within its Interconnection. This minimum IROL criteria will provide for greater continent-wide consistency as it ensures all RCs consider and identify what is allowable for each criteria. The SDT believes while this does change the current state – where no mandatory minimum criteria exist- it still allows for the RC to have the necessary flexibility to design its IROL	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R1 – RC SOL Methodology must include a description of how to identify the subset of SOLs that qualify as IROLs. • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL

Proposed Reliability Standard: FAC-011-4, Requirement R6		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
Coordinator Areas within an Interconnection.	methodology so that it can meet the reliability issues present in, and possibly unique to, its RC Area.	

Proposed Reliability Standard: FAC-011-4, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. Each Reliability Coordinator shall include in its SOL Methodology the criteria for developing the IROL T_V for any IROLs in its Reliability Coordinator Area. Each IROL T_V shall be less than or equal to 30 minutes.	For the most part, the substance of this requirement is not changed from the existing standard; it was previously contained in a part (*i.e.,* FAC-011-3 Part 3.7) and is now a stand-alone requirement. The only change is that the 30 minute time-period is specifically identified, whereas in the previous requirement only stated T_v.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_v.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Reliability Coordinator shall include in its SOL Methodology the method to address a Real-time operating state, where the next Contingency has the potential to cause System instability, Cascading outages or uncontrolled separation, but was not identified one or more days prior to the current day. The method shall address: **8.1.** Thresholds for initiating evaluation of potential impacts; **8.2.** A description of when pre-Contingency Load shedding is warranted to mitigate the condition; and, **8.3.** A review of the operating state experience for the purpose of determining whether an IROL should be established.	In Order No. 817, FERC noted that, "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability." The SDT believes that in certain circumstances, such as in response to forced outages or similar unforeseen events, Real-time operating conditions can occur such that a RTA identifies an operating state where the next Contingency could result in instability, uncontrolled separation or Cascading outages. When this operating condition occurs in Real-time, it is clear that System Operator(s) are expected to take urgent action to mitigate the N-1 insecure operating state. What is unclear, however, is whether this operating condition constitutes some sort of an "IROL exceedance" or mandates that other IROL-related Reliability Standards should be applied. The proposed requirement requires the RC SOL Methodology to prescribe a method for how to address the above-described Real-time operating state. This will allow for consistency by System Operators within an RC Area in responding to the Real-time operating state when tools or analysis indicate abnormal post-Contingency conditions (*e.g.*, unsolved Contingencies, high post-Contingency overloads). While the requirement treats the operating state similar to, and equally important to, what prepared response must be	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R3.7- RC SOL Methodology must include a description of the criteria for determining when violating an SOL qualifies as an IROL and criteria for developing any associated IROL T_V.

Proposed Reliability Standard: FAC-011-4, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	in place for resolving an IROL-type issue, the requirement does not focus on formally establishing the limit, but instead allowing the System Operator to act with urgency to address the temporary operating state at hand. Also Part 8.3 requires the RC Methodology prescribe an after-the-fact review of the operating state experience for the purpose of determining whether an IROL should be established in accordance with the RC SOL Methodology.	

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R9. Each Reliability Coordinator shall issue its SOL Methodology and any changes to the SOL Methodology, prior to the effective date, to: **9.1.** Each adjacent Reliability Coordinator within an Interconnection, and each Reliability Coordinator that requested and indicated it has a reliability-related need for the SOL Methodology;	For the most part, the substance of this requirement is not changed from the existing standard. A clarification was added to Part 9.1 that RCs should issue its SOL Methodology, and any associated changes, to the other RCs *within* its Interconnection.	**Mapping to existing FAC standards under revision:** • FAC-011-3 Requirement R4 – Requires the RC to issue its SOL Methodology, and any changes to the methodology, to its adjacent RCs and any RCs indicating a reliability-related need; to each PC and TP that models portions of its

Proposed Reliability Standard: FAC-011-4, Requirement R9		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
9.2. Each Planning Coordinator and Transmission Planner that models any portion of the Reliability Coordinator Area; and, **9.3.** Each Transmission Operator that operates in the Reliability Coordinator Area.		RC Area; and, each TOP that operates in its RC Area.

C. Proposed Revisions to FAC-014-3

Proposed Reliability Standard: FAC-014-3, Requirement R1		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R1. Each Reliability Coordinator shall establish Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area that are consistent with its System Operating Limit Methodology ("SOL Methodology") as established in FAC-011-4.	The current FAC-014-2 Requirement R1 requires that the RC ensure SOLs and IROLs are established pursuant to its SOL Methodology. This creates a situation where the RC is responsible for "ensuring" actions out of its control. The proposed revisions do not change the intent of the standard –that the RC develop the SOL Methodology for establishing SOLs in its RC Area, and the TOP following the RC SOL Methodology in establishing those SOLs. Accordingly, the proposed Requirement R2 requires that the TOP establish SOLs as required by the RC SOL Methodology. The SDT believes this clarifies the appropriate responsibilities of the respective functional entities, while not creating ambiguity in the requirements in requiring the RC to do something that the TOP is, in all actuality, required to do. 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.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R2		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R2. Each Transmission Operator shall establish SOLs for its portion of the Reliability Coordinator Area consistent with its Reliability Coordinator's SOL Methodology.	The SDT has removed language from the existing FAC-014-3 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 RC will issue a "Directive," or that 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 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 these SOLs must be established in accordance with (*i.e.*, pursuant to the "direction") identified in the RC's SOL Methodology.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R1 – Requires the RC to ensure SOLs and IROLs are establishing for its RC Area, consistent with its SOL Methodology. • FAC-014-2 Requirement R2 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R3. Each Reliability Coordinator shall determine stability limitations to be used in operations when the limitation impacts	The proposed approach by the SDT is that the RC SOL Methodology will set the method for how all stability limitations for its RC Area must be established (see, proposed	**Mapping to existing FAC standards under revision:**

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
more than one Transmission Operator in its Reliability Coordinator Area consistent with its SOL Methodology.	FAC-011-4 Requirement R4). The RC SOL Methodology must, among other things, specify the stability performance criteria for single Contingencies and multiple Contingencies, including any margins applied (see, proposed FAC-011-4 Part 4.1); meet the performance criteria for certain identified Contingencies listed in the standard (see, proposed FAC-011-4 Part 4.2); and describe how instability risks are identified (see, proposed FAC-011-4 Part 4.3). The TOP is required to establish stability limitation SOLs in accordance with everything outlined in the RC SOL Methodology. However, in addition to what is outlined above, the SDT believes that to the extent there are stability limitations that may impact more than one TOP in its RC Area, the RC should be responsible for determining these stability limitations (in accordance with its RC SOL Methodology – see, proposed FAC-011-4 Part 4.6). The purpose of providing a separate requirement for the RC to address this specific type of stability limitation is to provide clarity that there may be a stability limitation that is not appropriately labeled an "IROL," and thus, would not be covered by proposed Requirement R1. It is the position of the SDT that not all stability limitations are automatically "IROLs." For example, there may be instances of local, contained instability that are not appropriately designated	• N/A: This proposed requirement addresses what the SDT believes to be a gap in the existing requirements.

Proposed Reliability Standard: FAC-014-3, Requirement R3		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
	an "IROL," because labeling it as an IROL may require the TOP to take actions such as pre-Contingency load shedding, that is not warranted, and could actually cause a bigger reliability impact. However, when the stability limitation impacts more than one TOP, the SDT believes the RC should have primary responsibility for establishing that SOL.	

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R4. Each Reliability Coordinator shall provide the SOLs for its RC Area to adjacent Reliability Coordinators within an Interconnection and Reliability Coordinators who request and indicate a reliability-related need for those limits, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area. **4.1.** The Reliability Coordinators shall provide any updates to the SOL	The proposed Requirement R4 maintains the part of existing FAC-014-3 Requirement R5 which requires the TC to send the SOLs for its RC Area to adjacent RCs. The SDT has created a new/separate requirement related to communicating established IROLs (see proposed FAC-014-4 Requirement R5). The SDT added Part 4.1 to require the RC to provide updates to the SOLs to the impacted TOPs. It is expected that the RC and TOPs will establish a mutually agreeable means (pursuant to IRO-010-2 and TOP-003-3) for exchanging dynamically determined Facility Ratings or stability limitations.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R4		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
values established as part of Requirement R1 or Requirement R3 to impacted TOPs in its Reliability Coordinators Area in a mutually agreeable periodicity and format.		

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R5. Each Reliability Coordinator with an established IROL shall provide the following IROL information to adjacent Reliability Coordinators within an Interconnection, to other Reliability Coordinators that indicate a reliability-related need for the information, and to the Transmission Operators, Transmission Planners, and Planning Coordinators within its Reliability Coordinator Area: **5.1.** Identification of the Facilities that are critical to the derivation of the IROL.	See above explanation. This requirement was previously combined with the requirement to provide updates to both SOLs and IROLs (existing FAC-014-3 Requirement R5). The SDT separated these into two requirements – one for SOL and one for IROL – so that greater detail could be provided regarding the type of IROL-information that must be communicated by the RC.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Requirement R5 – Requires the TOP to establish SOLs consistent with the RC SOL Methodology.

Proposed Reliability Standard: FAC-014-3, Requirement R5		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
5.2. The value of the IROL and its associated IROL T_V. **5.3.** The associated Contingency(ies). **5.4.** The type of limitation represented by the IROL (*e.g.*, voltage collapse, angular stability).		

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
R6. Each Reliability Coordinator with an established IROL shall provide the following IROL information to Transmission Owners and Generation Owners within its RC Area: **6.1.** Identification of the Facilities that are owned by that entity, which are critical to the derivation of the IROL.	In FERC Order No. 777, FERC directed NERC to develop a means to assure that IROLs are communicated to transmission owners (*see*, P6 and P41). The purpose of this proposed requirement is to address the concerns raised by FERC in Order No. 777. The RC is required to provide the IROL information identified in Part 6.1 to Transmission Owners and Generator Owners in its RC Area. The SDT included Generator Owners because it believes that GOs, in addition to TOs, need to receive information relating to facilities that are critical to the derivation of the IROL. The SDT did not combine this with proposed Requirement R5 because the team believes that the owners only need IROL information related to their facilities that are critical to the	**Mapping to existing FAC standards under revision:** • N/A: This proposed requirement is intended to address the issues raised in FERC Order No. 777.

Proposed New/Revised Requirement	Explanation of Proposed Revision	Relevant Requirements in Existing Reliability Standard(s)
	derivation of the IROL. However, the owners do not need the information identified in proposed Parts 5.2 through Part 5.4, and further, this information may contain sensitive operator information not appropriate for open-ended sharing.	

Proposed Reliability Standard: FAC-014-3, Requirement R7		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R7. The Transmission Operator shall provide any SOLs and updates to those limits to its Reliability Coordinator and to the Transmission Service Providers that share its portion of the Reliability Coordinator Area.	The SDT did not make substantive changes to this requirement; however, the requirement previously existed as a "part" of a requirement and it is now a stand-alone requirement.	**Mapping to existing FAC standards under revision:** • FAC-014-2 Part 5.2 – Requires the TOP to provide its SOLs to the RC and Transmission Service Providers in its portion of the RC Area.

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**

Proposed Reliability Standard: FAC-014-3, Requirement R8		
Proposed New/Revised Requirement	**Explanation of Proposed Revision**	**Relevant Requirements in Existing Reliability Standard(s)**
R8. Each Planning Coordinator and Transmission Planner shall communicate the results of the stability analysis identified in its Planning Assessment and Transfer Capability assessment to each affected Reliability Coordinator and Transmission Operator. This shall include: **8.1.** The type of the instability (*e.g.*, voltage collapse, angular instability, transient voltage dip criteria violation); **8.2.** The Contingencies which result in the instability; **8.3.** 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 that was employed (or invoked) to address the instability; and, **8.4.** Any Corrective Action Plan associated with the instability.	Under proposed FAC-011-4 Part 4.4, the RC SOL Methodology must consider the stability limitations provided by the Planning Coordinator. Also, proposed FAC-014-3 Requirements R2 and R3, the applicable entities are required to establish stability limitations (if any) in accordance with the RC SOL Methodology. This requirement is intended to complement proposed FAC-011-4 Part 4.4 by ensuring that the planning entities provide the results of their stability analysis, including a list of those contingencies that are expected to produce the more severe System impacts, to the affected RC and TOP. This information may be relevant to the operating conditions for which the RC and TOP are determining SOLs. Further, FAC-013-2 requires that the PC have a methodology and annual assessment that identifies the weaknesses and limiting Facilities that could limit the ability of the Transmission System to reliably transfer energy. The results of the assessment, including the methodology used in the analysis, may contain information that may be relevant to the RC and TOP analysis for determining SOLs (and IROLs).	**Background regarding existing standards *not* under revision by SDT:** • TPL-001-4 • FAC-013-2 **Mapping to existing FAC standards under revision:** • FAC -011-3 Part 3.3 • FAC -014-2 Requirement R6

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%			

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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		

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
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 Hydro 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		

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
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		

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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~~		

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
						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%			

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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
			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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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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Line	Project#	Description	Document	Comment Type	Start Date	End Date	NPCC Submitted
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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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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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

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Note: RSC past comment forms are posted on the NPCC Website under "Standards - Regional Standards Comments."

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**

2. **Number:** PRC-006-NPCC-2

3. **Purpose:** The NPCC Automatic Underfrequency Load Shedding (UFLS) regional standard establishes more stringent and specific NPCC UFLS program requirements to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.

4. **Applicability:**

   4.1. Generator Owner

   4.2. Planning Coordinator

   4.3. Distribution Provider

   4.4. Transmission Owner

5. **Effective Date:**

   The first day of the first calendar quarter following applicable governmental and regulatory approvals.

B. Requirements

Rationale for Requirement R1: Attachment 1 of this document shows the NPCC underfrequency criteria for the eastern interconnection portion of NPCC. Note that Attachment 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

R1. Each Planning Coordinator in the Eastern Interconnection Portion of NPCC shall design a UFLS program having performance characteristics that prevents the frequency from remaining below 59.5 Hz for greater than 30 seconds in accordance with Attachment 1. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M1. Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

R2. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC PRC Standard on UFLS, to Distribution Providers, Generator Owners, and Transmission Owners within 30 days of receipt of a request. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

Rationale for Requirement R3: Demonstrate to the Regional Entity, via system studies, that the UFLS program will not meet performance requirements if all non-

BES generators identified in R3.1 trip above underfrequency trip threshold curve in Figure 1

R3. Each Planning Coordinator shall, within 30 days of completion of its UFLS system studies, identify to the Regional Entity all non-BES generation facilities, within its Planning Coordinator Area, that must not trip above the appropriate generator underfrequency trip threshold curve in Figure 1, in order to support acceptable UFLS program performance. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M3. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

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. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

4.1. The UFLS program shall be implemented by each Distribution Provider and Transmission Owner according to the frequency thresholds, nominal operating times and load shedding amounts specified in Attachment C, Tables 1 through 3.

4.2. Alternatively, the program can be implemented collectively by multiple Distribution Providers or Transmission Owners with less than 100 MW of individual peak net Load, as long they reside in the same UFLS Island identified by the Planning Coordinator per R2. These multiple Distribution Providers or Transmission owners, via mutual agreement, shall act as a single entity to provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to the frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3.

4.3. Whether implemented collectively or individually, the automatic UFLS program shall be implemented on an island basis. Each Distribution Provider and Transmission Owner shall provide the required load shedding amounts and frequency thresholds specified in the Attachment C, Tables 1 through 3, within each island identified per the NERC PRC Standard on UFLS.

M4. Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped in their respective areas, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

R5. Each Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in Attachment C, Tables 1 through 3,

Commented [DML1]: Do we still need rationale box if we have this?

such Distribution Provider or Transmission Owner by UFLS island shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

5.1. Within 30 calendar days of identification the tolerances cannot be met, in accordance to table 1, inform its Planning Coordinator.

5.1.1. Within 90 calendar days after informing of its Planning Coordinator that tolerances cannot be met, determine if tolerances can be met through adjustments and notify the Planning Coordinator of the determination and;

5.1.2. If adjustments are possible, make the adjustments within 180 calendar days after determining that adjustments are possible and notify the Planning Coordinator when complete.

5.2. If adjustments are not possible, then provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system. The study shall be completed within six months of notification per 5.1.1.

5.3. Within 30 calendar days, inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.3.1. Within 90 calendar days after informing the Planning Coordinator, determine if tolerances can be met through adjustments within the DP or TO system and notify the Planning Coordinator of the determination.

5.4. If adjustments are not possible, then provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3. The analysis shall be provided to the Planning Coordinator within 90 calendar days of determining that adjustments are not possible per 5.3.1.

M5. Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

Rationale for Requirement R6: Operation of underfrequency relays results directly in load being shed, interrupting service to customers. The security of underfrequency relays against misoperation is therefore paramount. The 100 ms minimum time delay specified in R6 serves to prevent premature activation of these relays during short-lived transient frequency excursions that may occur on a localized basis in the absence of a serious system event wherein UFLS would be appropriate. This intentional delay helps to ensure that the relays activate only for frequency excursions that are due to actual system events that require automatic UFLS to reestablish the balance of

generation to load.

R6. Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with a 100 ms minimum time delay. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M6. Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R6.

R7. Each Planning Coordinator shall develop and review settings for inhibit thresholds at least once per five calendar years (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

M7. Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R7.

R8. Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M8. Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R8.

R9. Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R8. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M9. Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

R10. Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R8 and based on the Planning Coordinator approved implementation plan in accordance with R9. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M10. Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets, completed work orders, or other documentation that demonstrates that it meets Requirement R10.

Rationale for Requirement R11: It is recognized that, ideally, the amount of load to

be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard universally, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. This being said, entities are required by R11 to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.

R11. Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load projected to be shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would disconnect load if triggered by the UFLS relays. If there is no local metering of the load through said switches, the load may be calculated from measurements made at the nearest available metering. (e.g., upstream metering on the distribution feeder that supplies the load to be shed). *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

M11. Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program to demonstrate that it meets Requirement R11.

R12. Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R15 and R18. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M12. Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R12.

R13. Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M13. Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R13.

R14. Each Generator Owner with a new generating unit, or an existing generator increasing its net capability by greater than 10% shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

14.1. Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

14.2. Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

M14. Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R14.

R15. Each Generator Owner of existing non-nuclear units in service prior to the effective date of this standard, as documented in accordance with Attachment B, that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

15.1. Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

15.2. Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

15.3. Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.

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M15. Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R15.

R16. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R15.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M16. Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R16.

R17. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R15.3 for generating units in its respective NPCC area. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

M17. Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R17.

R18. Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

- **18.1.** Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8 Hz.
- **18.2.** Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.
- **18.3.** Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

M18. Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R18.

R19. The Planning Coordinator shall maintain its UFLS program database as specified by the NERC PRC Standard on UFLS. This maintenance shall include a review of the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings for each UFLS relay, including those used for compensatory load shedding, if any. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M19. Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R19.

R20. The Planning Coordinator shall maintain the following additional UFLS program database parameters at least once every five years. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

20.1. The percentage of load shed at peak, at each load bus modeled in the NPCC library power flow case, for each frequency threshold specified in Attachment C, Tables 1 through 3, including those used for compensatory load shedding, if any ~~buses at which the Load is modeled in the NPCC library power flow case~~.

20.2. A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.3. A list of all generating units that may be tripped for overfrequency conditions below the appropriate generator overfrequency trip protection settings threshold curve in PRC-024 Attachment 1, including the frequency trip threshold and time delay for each protection system.

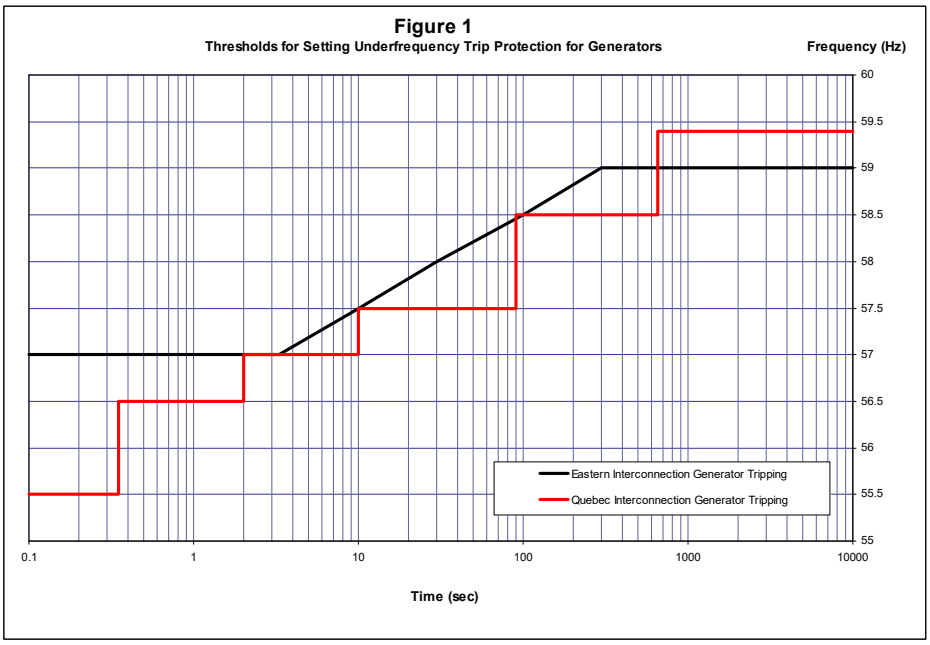
20.4~~3~~. ~~——~~The location and amount of shunt compensation that are automatically switched for voltage control or tripped by overvoltage protection. Associated overvoltage switching thresholds and trip settings shall also be provided. This overvoltage switching/tripping may or may not be coordinated with the UFLS program tripping.

20.5~~4~~. ~~———~~A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

M20. Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the additional UFLS program database parameters of Requirement R20.

Figure 1

Thresholds for Setting Underfrequency Trip Protection for Generators

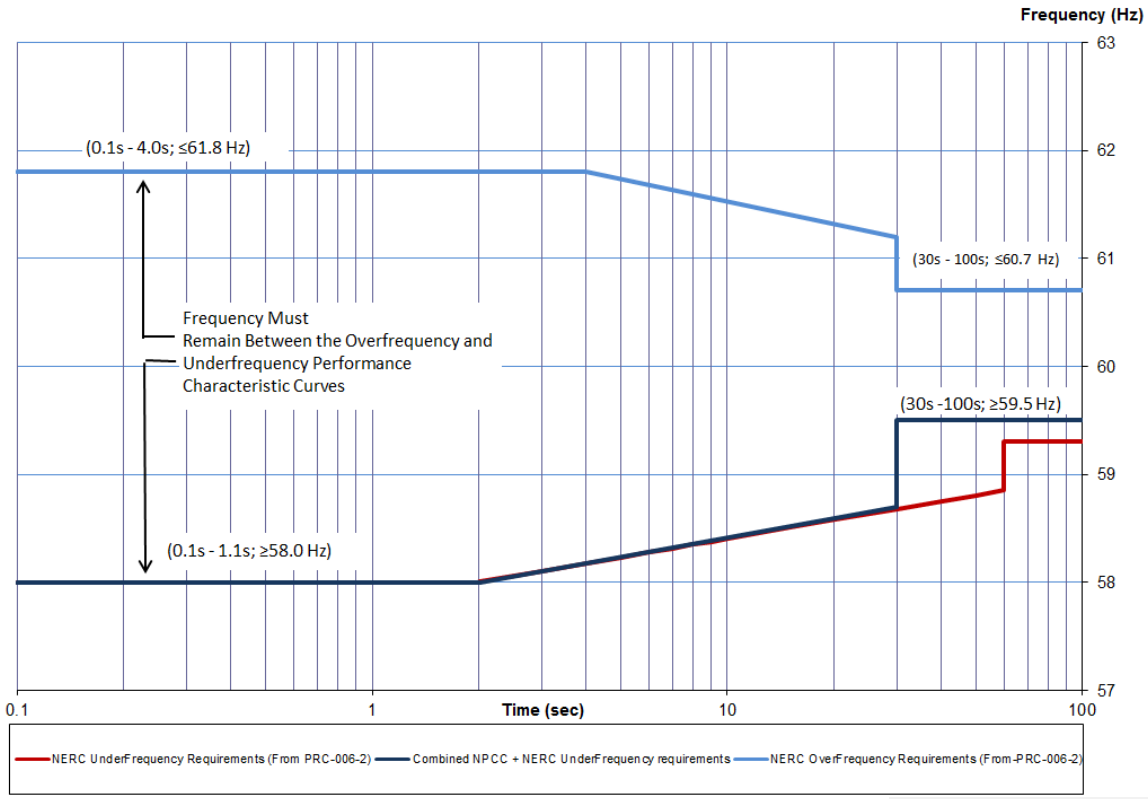


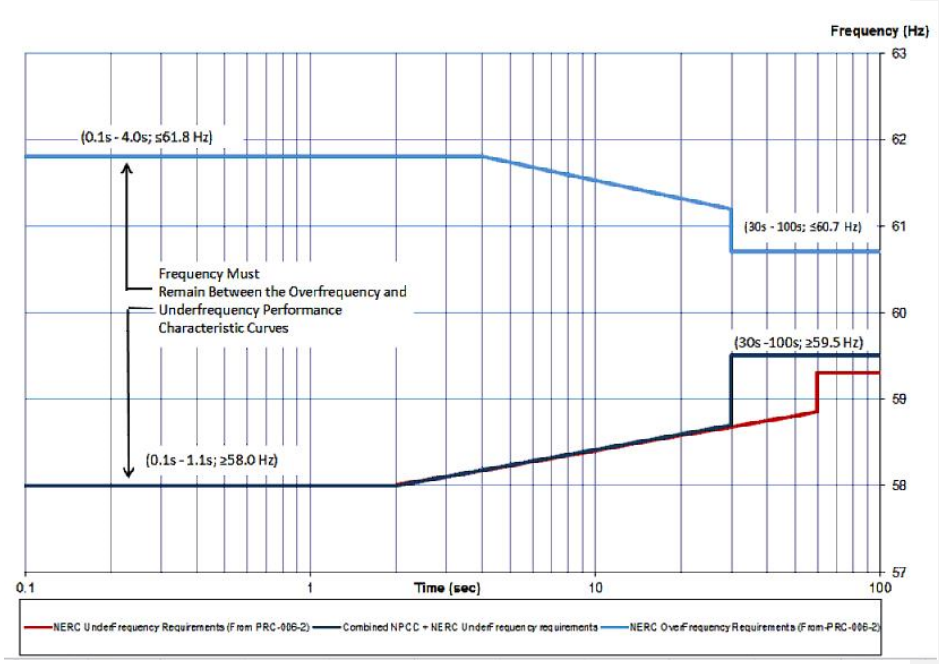
Attachment 1

PRC-006-NPCC-2

Underfrequency Load Shedding Program – Eastern Interconnection Frequency Hz Design Performance Requirements

PRC-006-NPCC-2 Attachment 1
Underfrequency Load Shedding Program - Eastern Interconnection
Design Performance Requirements





C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	N/A	N/A	Planning Coordinator did not design a UFLS program with the performance characteristics outlined in Attachment 1
R2	The Planning Coordinator identified and provided the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs and TOs as necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified and provided the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs and TOs as necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified and provided the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs, and TOs as necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified and provided the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs, and TOs as necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not provide the UFLS island boundaries within its Planning Coordinator Area to their DPs, GOPs, and TOs as necessary to support the UFLS program.
R3	The Planning Coordinator identified all non-BES generation facilities per R3 to the Regional Entity, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator identified all non-BES generation facilities per R3 to the Regional Entity, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator identified all non-BES generation facilities per R3 to the Regional Entity, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator identified all non-BES generation facilities per R3 to the Regional Entity, but did so more than 60 days after the request. or The Planning Coordinator failed to identify to the Regional Entity

				all the non-BES generation facilities per R3.
R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program as specified in Attachment C Tables 1-3 from their PC, reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island as identified by the PC in Requirement R2.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table 2 only, the need to deviate from providing two stages of UFLS.	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with the appropriate table.	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

R6	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set an underfrequency relay that is part of its region's UFLS program as specified in Requirement R6.
R7	N/A	N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R7.
R8	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R9	The Distribution Provider or	The Distribution Provider or	The Distribution Provider or	The Distribution Provider or

	Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.
R11				The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, (or calculated from measurements made at the nearest available metering), that were armed to shed at each UFLS stage coincident with their integrated hourly peak during

				the previous year.
R12	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in R15 or R18.
R13	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R14	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R14; Part 14.1. OR did not fulfill the obligation of Requirement R14, Part 14.2.	The Generator Owner did not fulfill the obligation of Requirement R14, Part 14.1. and did not fulfill the obligation of Requirement R14, Part 14.2.

R15	N/A	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1. OR did not fulfill the obligation of Requirement R15, Part 15.3.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1. and did not fulfill the obligation of Requirement R15, Part 15.3.
R16	N/A	N/A	N/A	The Planning Coordinator in Ontario, Quebec, or the Maritimes did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required in R15.3.
R17	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner within the PC areas of New York or New England, did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R18	N/A	The Generator Owner did not fulfill the obligation of Requirement R18, Part 18.3.	The Generator Owner did not fulfill the obligation of Requirement R18; Part 18.1. OR did not fulfill the obligation of Requirement R18, Part 18.2.	The Generator Owner did not fulfill the obligation of Requirement R18, Part 18.1. and did not fulfill the obligation of Requirement R18, Part 18.2.

R20	The Planning Coordinator did not have the set of additional data in its database for one of the parameters listed in Requirement 20, Parts 20.1. through 20.4.	The Planning Coordinator did not have the set of additional data in its database for two of the parameters listed in Requirement 20, Parts 20.1. through 20.4.	The Planning Coordinator did not have the set of additional data in its database for three of the parameters listed in Requirement 20, Parts 20.1. through 20.4.	The Planning Coordinator did not have the set of additional data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1. through 20.5.

PRC-006-NPCC-2 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements as part of its UFLS Assessment based on the NERC PRC Standard on UFLS:

1. The Planning Coordinator shall identify, compile and maintain a list of all existing non-nuclear generating units, in their Planning Coordinator area, in service prior to the effective date of Version 1 of the regional Standard (April, 2017 PRC-006-NPCC-1). The list must indicate generating units, if any, that have their underfrequency protections set to trip above the appropriate curve in Figure 1. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 In Ontario and in the Maritime provinces, the compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify, compile, and maintain a list of all of its existing non-nuclear generating units in service prior to the effective date of Version 1 of the regional Standard (April, 2017 PRC-006-NPCC-1). The list must indicate the Generator Owner's generating units, if any, that have their underfrequency protections set to trip above the appropriate curve in Figure 1. Generating Units not appearing on the list as of the effective date of Version 1 of the regional standard, as shown above, must have their Underfrequency protections set to trip on or below the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution

Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

Guidelines and Technical Basis

Standard PRC-006-2, R4 requires the Planning Coordinator to conduct a UFLS assessment at least once every five years. However, aside from a UFLS islanding event, it does not prescribe other factors or events which could warrant a new UFLS assessment in less than the five year time-frame.

PRC-006-NPCC-01 contained requirements if changes to load distribution impacted UFLS program performance (R21) but did not consider many other factors. The drafting team recommends retiring these requirements (R21, R22, R23) and replacing them with the following guidance.

Significant variations in the following factors could require a Planning Coordinator to conduct a new assessment:

- Changes to the BES that could modify the creation of islands or the severity of events such as new transmission topologies, revised protection schemes or new or revised RAS.
- Unforeseen islanding event
- Real and reactive load distribution (including changes to location of compensatory load shedding)
- Transmission Owner or Distribution Provider's inability to implement the UFLS program within the stated tolerances
- Load characteristics in particular frequency responsive load
- Automatic load restoration
- Generation geographical distribution
- Generator trip settings
- Generation mix in particular non-BES generation that may not be subject to frequency ride-through criteria

Generator dynamic modeling (MOD-027-1 - Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions) or system modeling (if variations in system response are detected under MOD-033 - Steady-State and Dynamic System Model Validation)

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

PRC-006-NPCC-02 Automatic Underfrequency Load Shedding

AGENDA FOR MEETING #6
April 6, 2017 9:00 a.m. – 4:00 p.m. EST
Hydro Quebec Office
Complexe Desjardins
150 Ste-Catherine West Street
Montreal, Quebec Canada H2X 3Y2
Attire: Business Casual

Dial-In: 415-655-0003 (USA) / 416-915-6530 (Canada) **Guest Code: 646507046**
Password: rM38dA8* (76383280 from phones)

	Name	Organization	Comment
1.	Gerry Dunbar	Northeast Power Coordinating Council	In Person
2.	Ruida Shu	Northeast Power Coordinating Council	In Person
3.	Juan Villar	FERC	In Person
4.	Vincent Morissette	Hydro Québec TransÉnergie	In Person
5.	Dean Latulipe	National Grid	In Person
6.	Dan Taft	Con Edison	In Person
7.	Brian Robinson	Utility Services	In Person
8.	Ben Wu	Orange & Rockland	In Person
9.	Tim Kucey	PSEG Fossil	Via Phone
10.	David Gordon	MMWEC	Via Phone
11.	Glen Paterson	TransCanada	Via Phone
12.	Nick Paratta	PLM	Via Phone
13.	Constantin Chitescu	OPG	Via Phone
14.	Dennis Fuentes	FERC	Via Phone
15.	Hamid Hamadani	Hydro One	Via Phone

Introductions and Chair's Remarks
Dan Taft called the meeting in order at 9:04AM.
Dan Taft the chair of the drafting team provided a brief introduction and background on the project.

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

Agenda Items:

1. **Purpose of this Standard Drafting Team (SAR)**
   Dan Taft reminded everyone the purpose of this standard drafting team.

2. **Review of Meeting Minutes**

3. **Open Action Item List**

   The standard drafting team reviewed the open action item list as a team.

4. **PRC-006-NPCC-01 Redline**

   Requirement 1:
   The SDT make no change to the existing redline of requirement 1.

   Requirement 2:
   There are 1470MW of generation below 20MW individual and 75MW aggregate.
   If these units trip above the curve the island in Connecticut will be in danger of collapsing.
   Action Item: Dan Taft will draft a letter to NERC Howard Gugel to discuss potential solutions to require the non-BES generation, not connected or connected to transmission and 20MW or smaller generation to trip within the curve.
   Action Item: Dean Latulipe will draft a redline on the existing Requirement 2 (new requirement 3).

   Requirement 4:
   The SDT made new modifications to requirement 4.

   Requirement 5:
   The SDT made minor changes to the requirement 5 language. Changed If a to “Each” Distribution Provideerand added “that”.

   Requirement 6:
   Requirement 6 was removed from the redline.

   Requirement 6:
   Removed 6.2 and incorporated 6.1 (100ms time delay) into the standard language.

   Requirement 7:
   The SDT changed the language to “five calendar years”.

   Requirement 8:
   The SDT left the requirement as it is.

   Requirement 9 and Requirement 10:
   These two requirements were swapped by the SDT.

   Requirement 11:
   The SDT added additional requirement language and rationale box from Dan Taft.

Requirement 12:
The SDT added “On or below” to the redline document.

Requirement 13:
The SDT did not make a change to the requirement.

Requirement 14:
The SDT removed “Scheduled to be in service on or after the effective date of this Standard” from the requirement language.

5. **Comparison Table, PRC-006-NPCC-1, PRC-006-2 and Directory 12**

6. **Discussion on the process for approbation**

7. **Next Steps**

Next face to face meeting will be on May 18-19, 2017 in Waterbury VT.

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.

A. Introduction

1. **Title:** **Automatic Underfrequency Load Shedding**
2. **Number:** PRC-006-NPCC-2~~1~~
3. **Purpose:** To provide a regional reliability standard that ensures the development of an effective automatic underfrequency load shedding (UFLS) program in order to preserve the security and integrity of the bulk power system during declining system frequency events in coordination with the NERC UFLS reliability standard characteristics.
4. **Applicability:**
   - **4.1.** Generator Owner
   - **4.2.** Planning Coordinator
   - **4.3.** Distribution Provider
   - **4.4.** Transmission Owner
5. **Effective Date:**

For the Eastern Interconnection & Québec Interconnection portions of NPCC excluding the Independent Electricity System Operator (IESO) Planning Coordinator area of NPCC in Ontario, Canada:

> The effective date for Requirements R1, R2, R3, R4, R5, R6, and R7 is the first day of the first calendar quarter following applicable regulatory approval but no earlier than January 1, 2016 The effective date for Requirements R8 through R23 is the first day of the first calendar quarter two years following applicable governmental and regulatory approval.

For the Independent Electricity System Operator (IESO) Planning Coordinator's area of NPCC in Ontario, Canada:

> All requirements are effective the first day of the first calendar quarter following applicable governmental and regulatory approval but no earlier than April 1, 2017.

B. Requirements

~~R1~~ R1 NPCC Under frequency Load Shedding Program - More Stringent Criteria

The NPCC underfrequency Criteria are in addition to, or more stringent or more specific than the NERC PRC Standard on UFLS, or any Regional Reliability standard requirements.

The intent of the NPCC automatic Under frequency Load Shedding program is to ensure that declining frequency is arrested and recovered in accordance with established NPCC performance requirements stipulated in this document.

Commented [DML1]: Dan to move to "purpose" section

~~Each Planning Coordinator shall design a UFLS program that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where an imbalance = [(load – actual generation output) / (load)], of up to 25 percent within the identified island(s).~~

R1. Each Planning Coordinator in the Eastern Interconnection Portion of NPCC shall design a UFLS program that meets the following performance characteristics in simulations of underfrequency conditions as prescribed in the NERC PRC Standard on UFLS.

~~R1.1 Frequency decline is arrested at no less than 58.0 Hz for the portions of NPCC in the Eastern Interconnection.~~

R1.1~~2~~ Frequency does not remain below 58.5 Hz for greater than 10 seconds, and does not remain below 59.5 Hz for greater than 30 seconds.

[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

Attachment 1 of this document shows the NPCC underfrequency criteria for the eastern interconnection portion of NPCC. Note that Attachment 1 also shows the NERC criteria as defined in the NERC PRC Standard on UFLS.

R2. Each Planning Coordinator shall provide UFLS island boundaries, as identified per the NERC PRC Standard on UFLS, to Distribution providers and Transmission owners within 30 days of a request.

Do not change language of existing R2 but it becomes:

~~**R3.** Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity the generation facilities within its Planning Coordinator Area necessary to support the UFLS program performance characteristics. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

Commented [DML2]: R3 language needs to be rewritten so as to clarify intent. Confusing as is.

R3 Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS:

R3.1 Identify to the Regional Entity all non-BES generation facilities, within its Planning Coordinator Area; that must nottrip above the appropriate generator underfrequency trip threshold curve in Figure 1.

R3.2 Demonstrate to the Regional Entity, via system studies, that the UFLS program will not meet performance requirements if all non-BES identified in R3.1 trip above underfrequency trip threshold curve in Figure 1.

[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

~~Each Planning Coordinator shall provide to the Transmission Owner, Distribution Provider, and Generator Owner within 30 days upon written request the requirements for entities aggregating the UFLS programs and requirements for compensatory load shedding program derived from each Planning Coordinator's system studies as determined by Requirement R1. [Violation Risk Factor: Low] [Time Horizon: Long Term Planning]~~

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. ~~for its Facilities~~

4.1 The program shall be implemented by each Distribution Provider and Transmission Owner according ~~based~~ to~~on~~ the frequency thresholds, ~~total~~ nominal operating times and load shedding amounts specified in Attachment C, Tables 1 through 3~~,~~

4.2 Alternatively, the program can be implemented ~~or~~ ~~shall~~ collectively ~~implement ,by mutual agreement~~ by ~~with~~ multiple~~one or more~~ Distribution Providers or~~and~~ Transmission Owners with less than 100 MW of individual peak net Load, as long they reside in the same UFLS Island. ~~within the same island~~ per ~~identified in. Requirement R1~~. These multiple Distribution Providers or Transmission owners~~and~~, via mutual agreement, shall act~~ing~~ as a single entity to~~,~~ provide an aggregated automatic UFLS program that sheds their coincident peak aggregated net Load according to~~, based on~~ the frequency thresholds, total nominal operating time and amounts specified in Attachment C, Tables 1 through 3.

4.3 Whether implemented collectively or individually, the automatic UFLS program shall be implemented on an island basis. Each Distribution Provider and Transmission Owner shall provide the required load shedding amounts and frequency thresholds specified in the Attachment C, Tables 1 through 3, within each island identified ~~in R2~~per the NERC PRC Standard on UFLS.

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

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R5

~~If a~~Each Distribution Provider or Transmission Owner that cannot meet the tolerances and/or number of stages and frequency set points specified in Attachment C, Tables 1 through 3, such Distribution Provider or Transmission Owner shall: .

~~Each Distribution Provider or Transmission Owner that must arm its load to trip on underfrequency in order to meet its requirements as specified and by doing so exceeds the tolerances and/or deviates from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Requirement R4 above, as applicable depending on its total peak net Load shall~~: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 Inform its Planning Coordinator of the need to exceed the stated tolerances or the number of stages as shown in UFLS Attachment C, Table 1 if applicable and

5.2 Provide its Planning Coordinator with a technical study that demonstrates that the Distribution Providers or Transmission Owners specific deviations from the requirements of UFLS Attachment C, Table 1 will not have a significant adverse impact on the bulk power system.

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5.3 Inform its Planning Coordinator of the need to exceed the stated tolerances of UFLS Attachment C, Table 2 or Table 3, and in the case of Attachment C, Table 2 only, the need to deviate from providing two stages of UFLS, if applicable, and

5.4 Provide its Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or Transmission Owner to comply with UFLS Attachment C Table 2 or Attachment C Table 3.

R6 ~~Each Distribution Provider and Transmission Owner in the Québec Interconnection portion of NPCC shall implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or shall collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating~~

~~time and amounts specified in Attachment C, Table 4. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

R~~6~~7 Each Distribution Provider and Transmission Owner shall set each underfrequency relay that is part of its region's UFLS program with a 100 ms~~with the following~~ minimum time delay.~~:~~

~~7.1 Eastern Interconnection 100 ms~~

~~7.2 Québec Interconnection 200 ms~~

[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R~~7~~8 Each Planning Coordinator shall develop and review settings for inhibit thresholds once per five calendar years (such as but not limited to voltage, current and time) to be utilized within its region's UFLS program.~~Each Planning Coordinator shall develop and review once per calendar year settings for inhibit thresholds (such as but not limited to voltage, current and time) of UFLS relays to be utilized within its region's UFLS program.~~ [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R~~8~~9 Each Planning Coordinator shall provide each Transmission Owner and Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds within 30 days of the initial determination of those inhibit thresholds and within 30 days of any changes to those thresholds. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R~~9~~10 ~~———————~~Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R8. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

~~———~~

R 10 Each Distribution Provider and Transmission Owner shall implement the inhibit threshold settings based on the notification provided by the Planning Coordinator in accordance with Requirement R~~8~~9. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

(The original R9 was swapped with R10)*****

~~**R11** Each Distribution Provider and Transmission Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with R9. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

R1~~2~~1 Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage coincident with their integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. If there is no local metering of the load through said switches, the load may be calculated from measurements made at the nearest available metering, e.g., upstream metering on the distribution feeder that supplies the load to be shed. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

RATIONALE BOX:

It is recognized that, ideally, the amount of load to be shed in each stage of the UFLS program for every entity should perfectly match that prescribed in this Standard universally, for all phases of the load cycle, i.e., seasonal (summer vs. winter), weekly (weekday vs. weekend vs. holidays), daily (morning, noon, and night), etc. for all of the identified islands. Practically, however, this is obviously not possible because the load cycles of the various areas and sub-areas within any given island do not perfectly track the load cycle of the overall island. The UFLS program, on the other hand, is designed based on peak conditions for the overall island. The percentages of actual load shedding that would occur for any conditions other than peak, therefore, can only approximate that prescribed in the Standard. This being said, entities are required by R12 to document measured loads in the UFLS program coincident with their own annual peak, whether or not that peak occurs at the same time or in the same season as the peak of the identified island in which their load resides. Using individual entity peaks vs. overall island peaks provides a consistent approach for accounting purposes among the very entities that are responsible for designing and maintaining their UFLS programs.

R1~~2~~3 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, on or below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted in Requirements R16 and R19. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R1~~3~~4 Each Generator Owner shall transmit the generator underfrequency trip setting and time delay to its Planning Coordinator within 45 days of the Planning Coordinator's request. [Violation Risk Factor: High] [Time Horizon: Operations Planning]

R1~~4~~5 Each Generator Owner with a new generating unit, ~~scheduled to be in service on or after the effective date of this Standard,~~ or an existing generator increasing its net capability by greater than 10% shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

15.1 Design measures to prevent the generating unit from tripping directly or indirectly for underfrequency conditions above the appropriate generator tripping threshold curve in Figure 1.

15.2 Design auxiliary system(s) or devices used for the control and protection of auxiliary system(s), necessary for the generating unit operation such that they will not trip the generating unit during underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

R16 Each Generator Owner of existing non-nuclear units in service prior to April , 2017 that PRC-006-NPCC-1 was effective~~the effective date of this standard~~ that have underfrequency protections set to trip above the appropriate curve in Figure 1 shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

16.1 Set the underfrequency protection to operate at the lowest frequency allowed by the plant design and licensing limitations.

16.2 Transmit the existing underfrequency settings and any changes to the underfrequency settings along with the technical basis for the settings to the Planning Coordinator.

16.3 Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping that is within the UFLS island identified by the Planning Coordinator in Requirement R2.~~.~~

Commented [DML3]: Guy to tightening up standard so that existing units that do meet curve, cant file to not meet curve.

R17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall apply the criteria described in Attachment A to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

Commented [DML4]: Vincent to modify attachment A

R18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall apply the criteria described in Attachment B to determine the compensatory load shedding that is required in Requirement R16.3 for generating units in its respective NPCC area. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

Commented [DML5]: Leave as is.

R19 Each Generator Owner of existing nuclear generating plants with units that have underfrequency relay threshold settings above the Eastern Interconnection generator tripping curve in Figure 1, based on their licensing design basis, shall: [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

19.1 Set the underfrequency protection to operate at as low a frequency as possible in accordance with the plant design and licensing limitations but not greater than 57.8Hz.

19.2 Set the frequency trip setting upper tolerance to no greater than + 0.1 Hz.

19.3 Transmit the initial frequency trip setting and any changes to the setting and the technical basis for the settings to the Planning Coordinator.

Commented [DML6]: Leave as is

R20 The Planning Coordinator shall update its UFLS ~~program d~~database **parameters** ~~as specified by the NERC PRC Standard on UFLS~~ parameters at least once every five years. Significant changes in generation, transmission, distribution, and/or load that materially impact the performance of UFLS program warrant updating of the effected parameters during the interim Transmission Review cycle within which the changes are implemented. ~~This database~~ These parameters shall include ~~the following information~~: [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]

20.1 For each UFLS relay, including those used for compensatory load shedding, the amount and location of load shed at peak, the corresponding frequency threshold and time delay settings.

20.2 The buses at which the Load is modeled in the NPCC library power flow case.

20.3 A list of all generating units that may be tripped for underfrequency conditions above the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, including the frequency trip threshold and time delay for each protection system.

20.4 The location and amount of shunt compensation that are automatically switched for voltage control or tripped by overvoltage protection. Associated overvoltage switching thresholds and trip settings shall also be provided. This overvoltage switching/tripping may or may not be coordinated with the UFLS program tripping.~~The location and amount of additional elements to be switched for voltage control that are coordinated with UFLS program tripping.~~

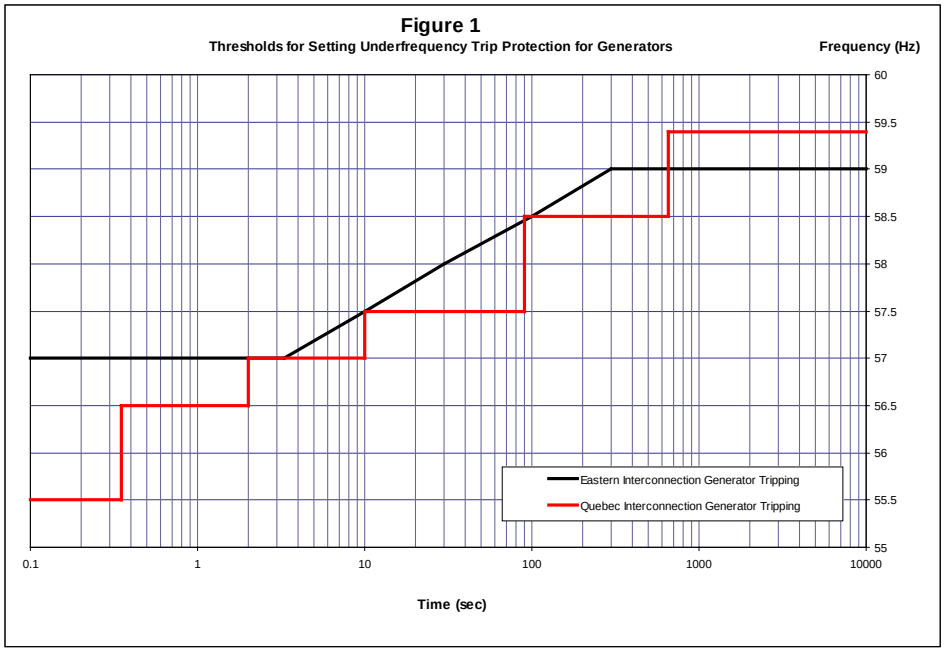
20.5 A list of all UFLS relay inhibit functions along with the corresponding settings and locations of these relays.

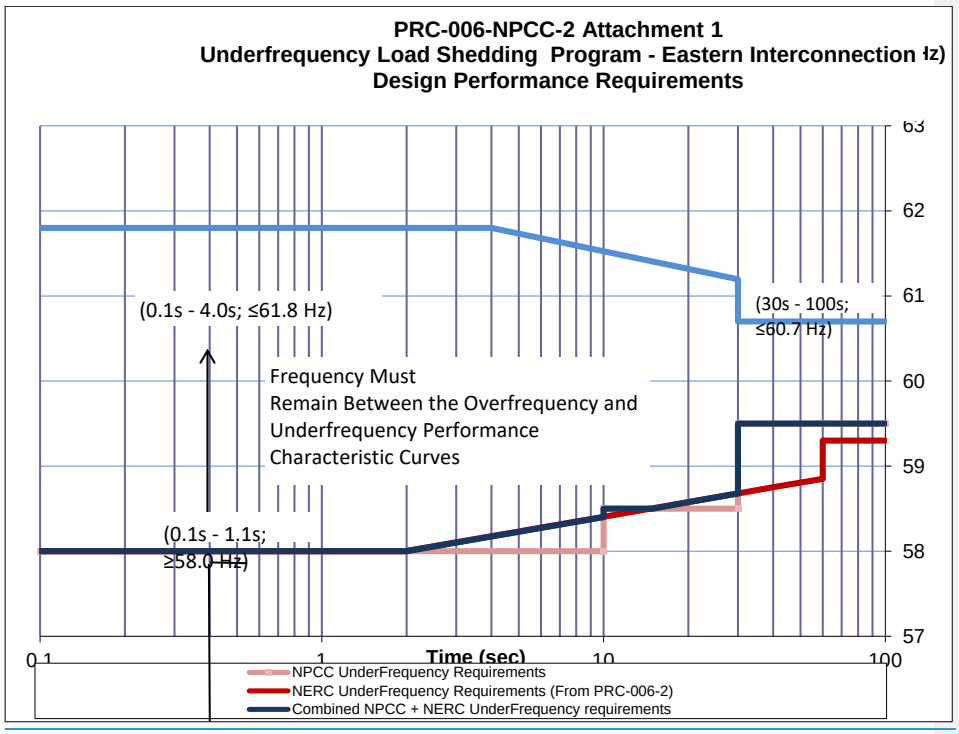
R21 Each Planning Coordinator shall notify each Distribution Provider, Transmission Owner, and Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy ~~-~~UFLS program performance characteristics as specified by the NERC PRC Standard on UFLS.[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

R22 ~~Each Distribution Provider, Transmission Owner and Generator Owner shall implement the load distribution changes based on the notification provided by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~

R23 ~~Each Distribution Provider, Transmission Owner and Generator Owner shall develop and submit an implementation plan within 90 days of the request from the Planning Coordinator for approval by the Planning Coordinator in accordance with Requirement R21. [Violation Risk Factor: Lower] [Time Horizon: Operations Planning]~~

Figure 1


Thresholds for Setting Underfrequency Trip Protection for Generators
Frequency (Hz)
60
59.5
59
58.5
58
57.5
57
56.5
56
55.5
55
0.1
1
10
100
1000
10000
Time (sec)
Eastern Interconnection Generator Tripping
Quebec Interconnection Generator Tripping



C. Measures

M1 Each Planning Coordinator shall have evidence such as reports, system studies and/or real time power flow data captured from actual system events and other dated documentation that demonstrates it meets Requirement R1.

M2. Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets requirement R2.

M3 Each Planning Coordinator shall have evidence such as dated documentation that demonstrates that it meets Requirement R3.

M4 Each Distribution Provider and Transmission Owner in the Eastern Interconnection portion of NPCC shall have evidence such as documentation or reports containing the location and amount of load to be tripped, and the corresponding frequency thresholds, on those circuits included in its UFLS program to achieve the individual and cumulative percentages identified in Requirement R4. (Attachment C Tables 1-3).

M5 Each Distribution Provider or Transmission Owner shall have evidence such as reports, analysis, system studies and dated documentation that demonstrates that it meets Requirement R5.

M6 Each Distribution Provider and Transmission Owner in the Québec Interconnection shall have evidence such as documentation or reports containing the location and amount of load to be tripped and the corresponding frequency thresholds on those circuits included in its UFLS program to achieve the load values identified in Table 4 of Requirement R6. (Attachment C Table 4).

M7 Each Distribution Provider and Transmission Owner shall have evidence such as documentation or reports that their underfrequency relays have been set with the minimum time delay, in accordance with Requirement R7.

M8 Each Planning Coordinator shall have evidence such as reports, system studies or analysis that demonstrates that it meets Requirement R8.

M9 Each Planning Coordinator shall provide evidence such as letters, emails, or other dated documentation that demonstrates that it meets Requirement R9.

M10 Each Distribution Provider and Transmission Owner shall provide evidence such as test reports, data sheets or other documentation that demonstrates that it meets Requirement R10.

M11 Each Distribution Provider and Transmission Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates that it meets Requirement R11.

M12 Each Distribution Provider and Transmission Owner shall provide evidence such as reports, spreadsheets or other dated documentation submitted to its Planning Coordinator that indicates the frequency set point, the net amount of load shed and the percentage of its peak load at each stage of its UFLS program coincident with the integrated hourly peak of the previous year that demonstrates that it meets Requirement R12.

M13 Each Generator Owner shall provide evidence such as reports, data sheets, spreadsheets or other documentation that demonstrates that it meets Requirement R13.

M14 Each Generator Owner shall provide evidence such as emails, letters or other dated documentation that demonstrates that it meets Requirement R14.

M15 Each Generator Owner shall provide evidence such as reports, data sheets, specifications, memorandum or other documentation that demonstrates that it meets Requirement R15.

M16 Each Generator Owner with existing non-nuclear units in service prior to the effective date of this Standard which have underfrequency tripping that is not compliant with Requirement R13 shall provide evidence such as reports, spreadsheets, memorandum or dated documentation demonstrating that it meets Requirement R16.

M17 Each Planning Coordinator in Ontario, Quebec and the Maritime provinces shall provide evidence such as emails, memorandum or other documentation that demonstrates that it followed the methodology described in Attachment A and meets Requirement R17.

M18 Each Generator Owner, Distribution Provider or Transmission Owner within the Planning Coordinator area of ISO-NE or the New York ISO shall provide evidence such as emails, memorandum, or other documentation that demonstrates that it followed the methodology described in Attachment B and meets Requirement R18.

M19 Each Generator Owner of nuclear units that have been specifically identified by NPCC as having generator trip settings above the generator trip curve in Figure 1 shall provide evidence such as letters, reports and dated documentation that demonstrates that it meets Requirement R19.

M20 Each Planning Coordinator shall provide evidence such as spreadsheets, system studies, or other documentation that demonstrates that it meets the requirements of Requirement R20.

M21 Each Planning Coordinator shall provide evidence such as emails, memorandum or other dated documentation that it meets Requirement R21.

M22 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as reports, spreadsheets or other documentation that demonstrates that it meets Requirement R22.

M23 Each Distribution Provider, Transmission Owner and Generator Owner shall provide evidence such as letters, emails or other dated documentation that demonstrates it meets Requirement 23.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

NPCC Compliance Committee

1.2. Compliance Monitoring Period and Reset Time Frame

Not Applicable

1.3. Data Retention

The Distribution Provider and Transmission Owner shall keep evidences for three calendar years for Measures 4, 5, 6,7,10, 11, and 12.

The Planning Coordinator shall keep evidence for three calendar years for Measures 1, 2, 3, 8, 9, 20, and 21.

The Planning Coordinator in Ontario, Quebec, and the Maritime Provinces shall keep evidence for three calendar years for Measure 17.

The Distribution Provider, Transmission Owner, and Generator Owner shall keep evidences for three calendar years for Measures 18, 22, and 23.

The Generator Owner shall keep evidence for three calendar years for Measures 13, 14, 15, 16, and 19.

1.4. Compliance Monitoring and Assessment Processes

Self -Certifications.

Spot Checking.

Compliance Audits.

Self- Reporting.

Compliance Violation Investigations.

Complaints.

1.5. Additional Compliance Information

None.

2. Violation Severity Levels

Requirement	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	N/A	**N/A**	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs. or Did not establish requirements for compensatory load shedding.	Planning Coordinator did not establish requirements for entities aggregating their UFLS programs and did not establish requirements for compensatory load shedding.
R2	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 30 days but less than 41 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 40 days but less than 51 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 50 days but less than 61 days after completion of the system studies.	The Planning Coordinator identified the generation facilities within its Planning Coordinator Area necessary to support the UFLS program, but did so more than 60 days after completion of the system studies. or The Planning Coordinator did not identify the generation facilities within its Planning Coordinator Area necessary to support the UFLS program.
R3	The Planning Coordinator provided the requested information, but did so more than 30 days but less than 41 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 40 days but less than 51 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 50 days but less than 61 days to the requesting entity.	The Planning Coordinator provided the requested information, but did so more than 60 days after the request. or The Planning Coordinator failed to provide the requested information.

R4	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to implement an automatic UFLS program reflecting normal operating conditions excluding outages, for its Facilities or collectively implemented by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on frequency thresholds, total nominal operating time, and amounts specified in the appropriate included tables.
R5	N/A	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not inform the Planning Coordinator of the need to exceed the stated tolerances of UFLS Table 2 or Table 3, and in the case of Table	The Distribution Provider or Transmission Owner armed its load to trip on underfrequency in order to meet its minimum obligations and by doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load, but did not provide the Planning Coordinator with an analysis demonstrating that no alternative load shedding solution is available that would allow the Distribution Provider or	The Distribution Provider or Transmission Owner did not arm its load to trip on underfrequency in order to meet its minimum obligations and in doing so exceeded the tolerances and/or deviated from the number of stages and frequency set points of the UFLS program as specified in the tables contained in Attachment C, as applicable depending on their total peak net Load.

		2 only, the need to deviate from providing two stages of UFLS.	Transmission Owner to comply with the appropriate table.	
R6	N/A	N/A	T	The Distribution Provider or Transmission Owner in the Québec Interconnection portion of NPCC did not implement an automatic UFLS program for its Facilities based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4 or did not collectively implement by mutual agreement with one or more Distribution Providers and Transmission Owners within the same island, identified in Requirement R1, an aggregated automatic UFLS program that sheds Load based on the frequency thresholds, slopes, total nominal operating time and amounts specified in Attachment C, Table 4.
R7	N/A	N/A	N/A	The Distribution Provider or Transmission Owner failed to set

				an underfrequency relay that is part of its region's UFLS program as specified in Requirement R7.
R8		N/A	The Planning Coordinator developed inhibit thresholds as specified in Requirement R8 but did not perform the review once per calendar year.	The Planning Coordinator did not develop inhibit thresholds as specified in Requirement R8.
R9	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 30 days but less than 41 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 40 days but less than 51 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 50 days but less than 61 days of the initial determination or any subsequent change to the inhibit thresholds.	The Planning Coordinator provided to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds more than 60 days after the initial determination or any subsequent change to the inhibit thresholds. or The Planning Coordinator did not provide to a Transmission Owner or Distribution Provider within its Planning Coordinator area the applicable inhibit thresholds.
R10	N/A	N/A	N/A	The Distribution Provider or Transmission Owner did not implement the inhibit threshold based on the notification provided by the Planning Coordinator in accordance with Requirement R9.

R11	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider or Transmission Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider or Transmission Owner did not develop its implementation plan.
R12				The Transmission Owner or Distribution Provider did not provide documentation to its Planning Coordinator of actual net load data or updates to the data that would be shed by the UFLS relays, as determined by measuring actual metered load through the switches that would be opened by the UFLS relays, that were armed to shed at each UFLS stage coincident with their integrated hourly peak during the previous year.
R13	N/A	N/A	N/A	The Generator Owner did not set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted.

R14	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 45 days and less than 56 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 55 days and less than 66 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 65 days and less than 76 days of the Planning Coordinator's request.	The Generator Owner transmitted the generator underfrequency trip setting and time delay to its Planning Coordinator more than 75days after the Planning Coordinator's request. or The Generator Owner did not transmit the generator underfrequency trip setting and time delay to its Planning Coordinator.
R15	N/A	N/A	The Generator Owner did not fulfill the obligation of Requirement R15; Part 15.1 OR did not fulfill the obligation of Requirement R15, Part 15.2.	The Generator Owner did not fulfill the obligation of Requirement R15, Part 15.1 and did not fulfill the obligation of Requirement R15, Part 15.2.
R16	N/A	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.2.	The Generator Owner did not fulfill the obligation of Requirement R16; Part 16.1 OR did not fulfill the obligation of Requirement R16, Part 16.3.	The Generator Owner did not fulfill the obligation of Requirement R16, Part 16.1 and did not fulfill the obligation of Requirement R16, Part 16.3.

R17	N/A	N/A	N/A	The Planning Coordinator did not apply the methodology described in Attachment A to determine the compensatory load shedding that is required.
R18	N/A	N/A	N/A	The Generator Owner, Distribution Provider, or Transmission Owner did not apply the methodology described in Attachment B to determine the compensatory load shedding that is required.
R19	N/A	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.3.	The Generator Owner did not fulfill the obligation of Requirement R19; Part 19.1 OR did not fulfill the obligation of Requirement R19, Part 19.2.	The Generator Owner did not fulfill the obligation of Requirement R19, Part 19.1 and did not fulfill the obligation of Requirement R19, Part 19.2.
R20	The Planning Coordinator did not have data in its database for one of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for two of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for three of the parameters listed in Requirement 20, Parts 20.1 through 20.5.	The Planning Coordinator did not have data in its database for four or more of the parameters listed in Requirement 20, Parts 20.1 through 20.5.

R21	N/A	N/A	N/A	The Planning Coordinator did not notify a Distribution Provider, Transmission Owner, or Generator Owner within its Planning Coordinator area of changes to load distribution needed to satisfy UFLS program requirements.
R22	N/A	N/A	N/A	The Distribution Provider, Transmission Owner, or Generator Owner did not implement the load distribution changes based on the notification provided by the Planning Coordinator.
R23	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 90 days but less than 101 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 100 days but less than 111 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 110 days but less than 121 days after the request from the Planning Coordinator.	The Distribution Provider. Transmission Owner or Generator Owner developed and submitted its implementation plan more than 120 days after the request from the Planning Coordinator. or The Distribution Provider. Transmission Owner or Generator Owner did not develop its implementation plan.

PRC-006-NPCC-1 Attachment A

Compensatory Load Shedding Criteria for Ontario, Quebec, and the Maritime Provinces:

The Planning Coordinator in Ontario, Quebec and the Maritime provinces is responsible for establishing the compensatory load shedding requirements for all existing non-nuclear units in its NPCC area with underfrequency protections set to trip above the appropriate curve in Figure 1. In addition, it is the Planning Coordinator's responsibility to communicate these requirements to the appropriate Distribution Provider or Transmission Owner and to ensure that adequate compensatory load shedding is provided in all islands identified in Requirement R1 in which the unit may operate.

The methodology below provides a set of criteria for the Planning Coordinator to follow for determining compensatory load shedding requirements:

1. The Planning Coordinator shall identify, compile and maintain an updated list of all existing non-nuclear generating units in service prior to the effective date of this standard that have underfrequency protections set to trip above the appropriate curve in Figure 1. The list shall include the following information for each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 All islands within which the unit may operate, as identified in Requirement R1

2. For each generating unit identified in (1) above, the Planning Coordinator shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 Arrange for a Distribution Provider or Transmission Owner that owns UFLS relays within the island(s) identified by the Planning Coordinator in Requirement R1 within which the generator may operate to provide compensatory load shedding.

    2.2 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4..

    2.3 The compensatory load shedding shall be provided at the UFLS program stage (or threshold stage for Quebec) with a frequency threshold setting that corresponds to the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1 during an underfrequency event. If the highest

frequency at which the subject generator will trip above the appropriate curve in Figure 1 does not correspond to a specific UFLS program stage threshold setting, the compensatory load shedding shall be provided at the UFLS program stage with a frequency threshold setting that is higher than the highest frequency at which the subject generator will trip above the appropriate curve in Figure 1.

2.4 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment B

Compensatory Load Shedding Criteria for ISO-NE and NYISO:

The Generator Owner in the New England states or New York State are responsible for establishing a compensatory load shedding program for all existing non-nuclear units with underfrequency protection set to trip above the appropriate curve in Figure 1 of this standard. The Generator Owner shall follow the methodology below to determine compensatory load shedding requirements:

1. The Generator Owner shall identify and compile a list of all existing non-nuclear generating units in service prior to the effective date of this standard that has underfrequency protection set to trip above the appropriate curve in Figure 1. The list shall include the following information associated with each unit:

    1.1 Generator name and generating capacity
    1.2 Underfrequency protection trip settings, including frequency trip set points and time delays
    1.3 Physical and electrical location of the unit
    1.4 Smallest island within which the unit may operate as identified by the Planning Coordinator in Requirement R1 of this Standard.

2. For each generating unit identified in (1) above, the Generator Owner shall establish the requirements for compensatory load shedding based on criteria outlined below:

    2.1 In cases where a Distribution Provider or Transmission Owner has coordinated protection settings with the Generator Owner to cause the generator to trip above the appropriate curve in Figure 1, the Distribution Provider or Transmission Owner is responsible to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.2 In cases where a Generator Owner has a generator that cannot physically meet the set points defined by the appropriate curve in Figure 1, the Generator Owner shall arrange for a Distribution Provider or Transmission Owner to provide the appropriate amount of compensatory load to be shed within the smallest island identified by the Planning Coordinator in Requirement R1 of this standard.

    2.3 The compensatory load shedding that is provided by the Distribution Provider or Transmission Owner shall be in addition to the amount that the Distribution Provider or Transmission Owner is required to shed as specified in Requirement R4.

2.4 The compensatory load shedding shall be provided at the UFLS program stage with the frequency threshold setting at or closest to but above the frequency at which the subject generator will trip.

2.5 The amount of compensatory load shedding shall be equivalent (±5%) to the average net generator megawatt output for the prior two calendar years, as specified by the Planning Coordinator, plus expected station loads to be transferred to the system upon loss of the facility. The net generation output should only include those hours when the unit was a net generator to the electric system.

In the specific instance of a generating unit that has been interconnected to the electric system for less than two calendar years, the amount of compensatory load shedding shall be equivalent (±5%) to the maximum claimed seasonal capability of the generator over two calendar years, plus expected station loads to be transferred to the system upon loss of the facility.

PRC-006-NPCC-1 Attachment C

UFLS Table 1: Eastern Interconnection

Distribution Providers and Transmission Owners with 100 MW or more of peak net Load shall implement a UFLS program with the following attributes:

Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
59.5	0.30	6.5 – 7.5	6.5 – 7.5
59.3	0.30	6.5 – 7.5	13.5 – 14.5
59.1	0.30	6.5 – 7.5	20.5 – 21.5
58.9	0.30	6.5 – 7.5	27.5 – 28.5
59.5	10.0	2 – 3	29.5 – 31.5

UFLS Table 2: Eastern Interconnection

Distribution Providers and Transmission Owners with 50 MW or more and less than 100 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time(s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	14-25	14-25
2	59.1	0.30	14-25	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 3: Eastern Interconnection

Distribution Providers and Transmission Owners with 25 MW or more and less than 50 MW of peak net Load shall implement a UFLS program with the following attributes:

UFLS Stage	Frequency Threshold (Hz)	Total Nominal Operating Time (s)[1]	Load Shed at Stage as % of TO or DP Load	Cumulative Load Shed as % of TO or DP Load
1	59.5	0.30	28-50	28-50

1. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communication times, and the rated breaker interrupting time. The underfrequency relay operating time is measured from the time when frequency passes through the frequency threshold setpoint, using a test rate of frequency decay of 0.2 Hz per second. If the relay operating time is dependent on the rate of frequency decay, the underfrequency relay operating time and any subsequent testing of the UFLS relays shall utilize a test rate of linear frequency decay of 0.2 Hz per second.

UFLS Table 4: Quebec Interconnection

Commented [DML7]: Quebec want this out of standard

	Rate	Frequency (Hz)	MW at peak (*Load must be fixed at all times when above 60% of peak load..)	Mvar at peak	Total Nominal Operating Time (s)[2]
Threshold Stage 1	——	58.5	1000*	1000	0.30
Threshold Stage 2	——	58.0	800*	800	0.30
Threshold Stage 3	——	57.5	800	800	0.30
Threshold Stage 4	——	57.0	800	800	0.30
Threshold Stage 5 (anti-stall)	——	59.0	500	500	20.0
Slope Stage 1	-0.3 Hz/s	58.5	400	400	0.30
Slope Stage 2	-0.4 Hz/s	59.8	800*	800	0.30
Slope Stage 3	-0.6 Hz/s	59.8	800*	800	0.30
Slope Stage 4	-0.9 Hz/s	59.8	800	800	0.30

2. The total nominal operating time includes the underfrequency relay operating time plus any interposing auxiliary relay operating times, communications time, and the rated breaker interrupting time. The underfrequency relay operating time shall be measured from the time when the frequency passes through the frequency threshold set point.

Guidelines and Technical Basis

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Standard PRC-006-2, R4 requires the Planning Coordinator to conduct a UFLS assessment at least once every five years. However, aside from a UFLS islanding event, it does not prescribe other factors or events which could warrant a new UFLS assessment in less than the five year time-frame.

PRC-006-NPCC-01 contained requirements if changes to load distribution impacted UFLS program performance (R21) but did not consider many other factors. The drafting team recommends retiring these requirements (R21, R22, R23) and replacing them with the following guidance.

Significant variations in the following factors could require a Planning Coordinator to conduct a new assessment:

- Changes to the BES that could modify the creation of islands or the severity of events such as new transmission topologies, revised protection schemes or new or revised RAS.
- Unforeseen islanding event
- Real and reactive load distribution (including changes to location of compensatory load shedding)
- Transmission Owner or Distribution Provider's inability to implement the UFLS program within the stated tolerances
- Load characteristics in particular frequency responsive load
- Automatic load restoration
- Generation geographical distribution
- Generator trip settings
- Generation mix in particular non-BES generation that may not be subject to frequency ride-through criteria

Generator dynamic modeling (MOD-027-1 - Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions) or system modeling (if variations in system response are detected under MOD-033 - Steady-State and Dynamic System Model Validation)

NPCC's Regional Standard on Underfrequency Load Shedding

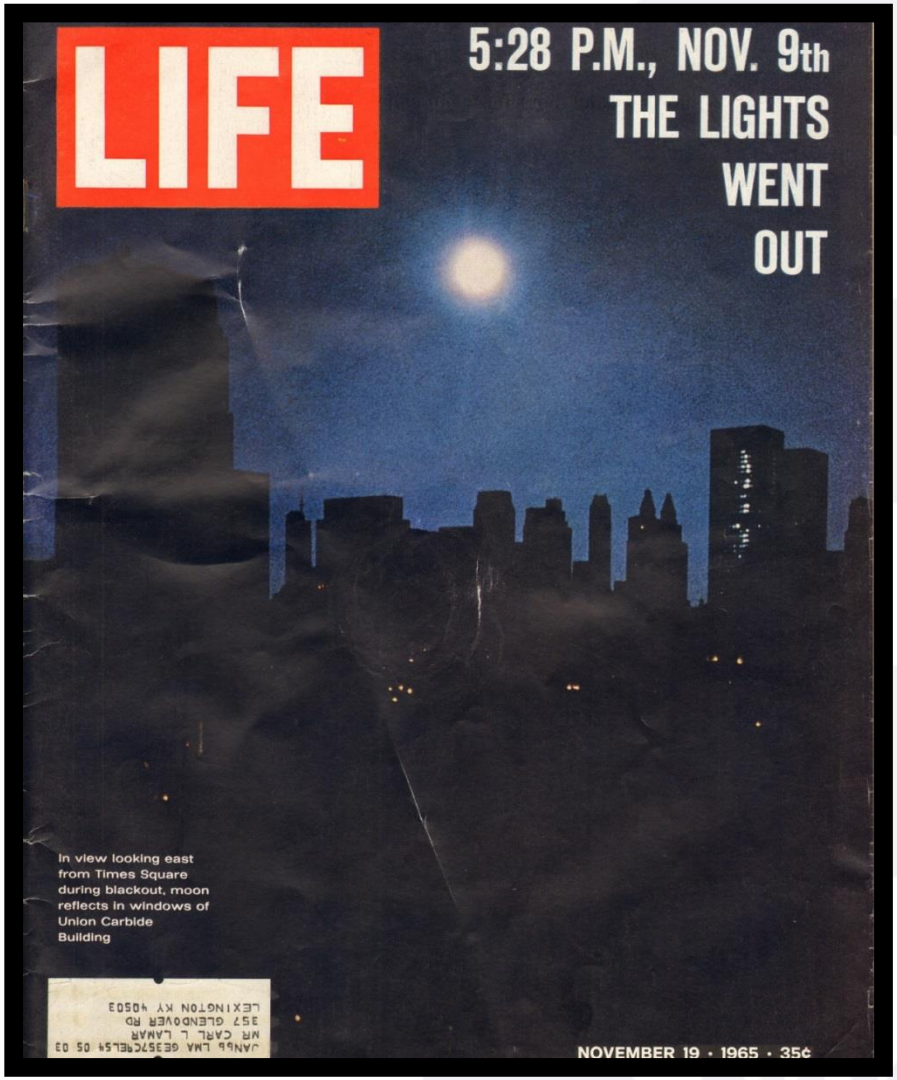
PRC-006-NPCC-2

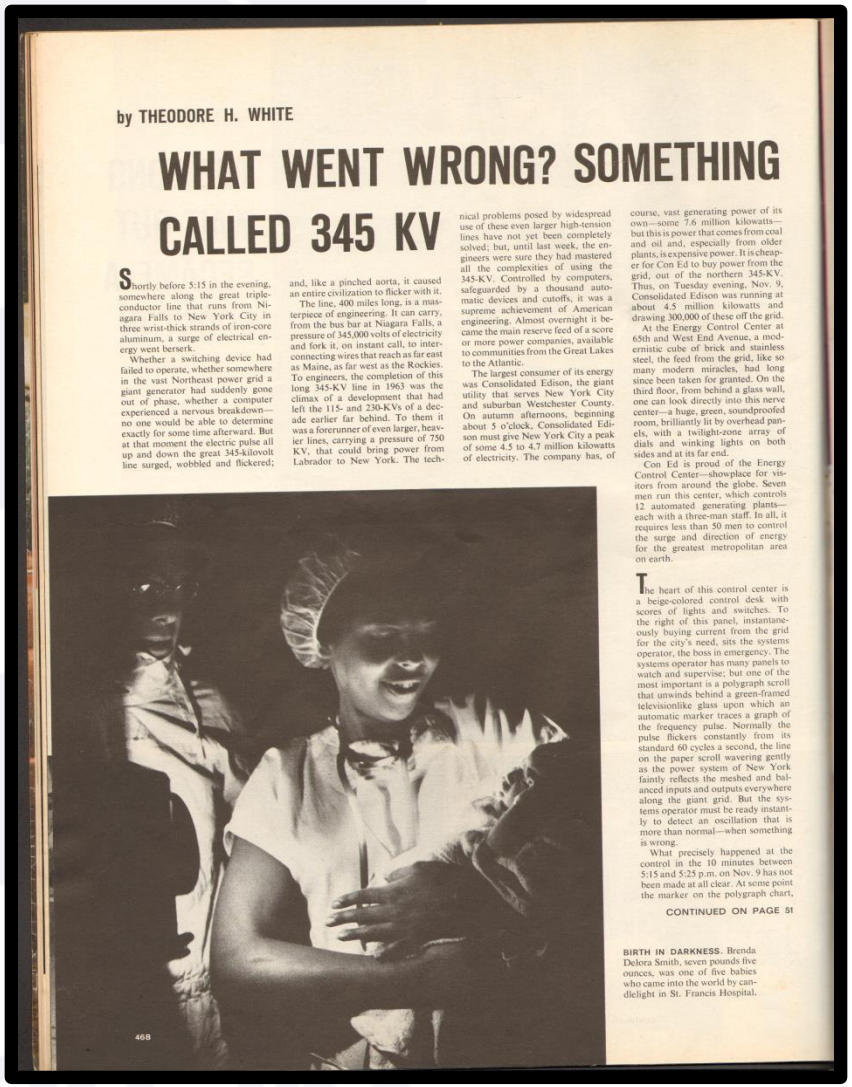
Progress Report of Standard Drafting Team

Dean Latulipe and Dan Taft

May 24, 2017

November 9, 1965





by THEODORE H. WHITE

WHAT WENT WRONG? SOMETHING CALLED 345 KV

Shortly before 5:15 in the evening, somewhere along the great triple-conductor line that runs from Niagara Falls to New York City in three wrist-thick strands of iron-core aluminum, a surge of electrical energy went berserk.

Whether a switching device had failed to operate, whether somewhere in the vast Northeast power grid a giant generator had suddenly gone out of phase, whether a computer experienced a nervous breakdown—no one would be able to determine exactly for some time afterward. But at that moment the electric pulse all up and down the great 345-kilovolt line surged, wobbled and flickered; and, like a pinched aorta, it caused an entire civilization to flicker with it.

The line, 400 miles long, is a masterpiece of engineering. It can carry, from the bus bar at Niagara Falls, a pressure of 345,000 volts of electricity and fork it, on instant call, to interconnecting wires that reach as far east as Maine, as far west as the Rockies. To engineers, the completion of this long 345-KV line in 1963 was the climax of a development that had left the 115- and 230-KVs of a decade earlier far behind. To them it was a forerunner of even larger, heavier lines, carrying a pressure of 750 KV, that could bring power from Labrador to New York. The technical problems posed by widespread use of these even larger high-tension lines have not yet been completely solved; but, until last week, the engineers were sure they had mastered all the complexities of using the 345-KV. Controlled by computers, safeguarded by a thousand automatic devices and cutoffs, it was a supreme achievement of American engineering. Almost overnight it became the main reserve feed of a score or more power companies, available to communities from the Great Lakes to the Atlantic.

The largest consumer of its energy was Consolidated Edison, the giant utility that serves New York City and suburban Westchester County. On autumn afternoons, beginning about 5 o'clock, Consolidated Edison must give New York City a peak of some 4.5 to 4.7 million kilowatts of electricity. The company has, of course, vast generating power of its own—some 7.6 million kilowatts—but this is power that comes from coal and oil and, especially from older plants, is expensive power. It is cheaper for Con Ed to buy power from the grid, out of the northern 345-KV. Thus, on Tuesday evening, Nov. 9, Consolidated Edison was running at about 4.5 million kilowatts and drawing 300,000 of these off the grid.

At the Energy Control Center at 65th and West End Avenue, a modernistic cube of brick and stainless steel, the feed from the grid, like so many modern miracles, had long since been taken for granted. On the third floor, from behind a glass wall, one can look directly into this nerve center—a huge, green, soundproofed room, brilliantly lit by overhead panels, with a twilight-zone array of dials and winking lights on both sides and at its far end.

Con Ed is proud of the Energy Control Center—showplace for visitors from around the globe. Seven men run this center, which controls 12 automated generating plants—each with a three-man staff. In all, it requires less than 50 men to control the surge and direction of energy for the greatest metropolitan area on earth.

The heart of this control center is a beige-colored control desk with scores of lights and switches. To the right of this panel, instantaneously buying current from the grid for the city's need, sits the systems operator, the boss in emergency. The systems operator has many panels to watch and supervise; but one of the most important is a polygraph scroll that unwinds behind a green-framed televisionlike glass upon which an automatic marker traces a graph of the frequency pulse. Normally the pulse flickers constantly from its standard 60 cycles a second, the line on the paper scroll wavering gently as the power system of New York faintly reflects the meshed and balanced inputs and outputs everywhere along the giant grid. But the systems operator must be ready instantly to detect an oscillation that is more than normal—when something is wrong.

What precisely happened at the control in the 10 minutes between 5:15 and 5:25 p.m. on Nov. 9 has not been made at all clear. At some point the marker on the polygraph chart,

CONTINUED ON PAGE 51

BIRTH IN DARKNESS. Brenda Delora Smith, seven pounds five ounces, was one of five babies who came into the world by candlelight in St. Francis Hospital.

Recommendation Number 9

STONE & WEBSTER ENGINEERING CORPORATION

225 FRANKLIN STREET, BOSTON, MASSACHUSETTS 02107

NEW YORK
BOSTON
CHICAGO
GARDEN CITY
HOUSTON
LOS ANGELES
SAN FRANCISCO
SEATTLE

November 4, 1966

DESIGN
CONSTRUCTION
REPORTS
APPRAISALS
EXAMINATIONS
CONSULTING
ENGINEERING

Sponsor Companies,
Northeast Interconnection Study.

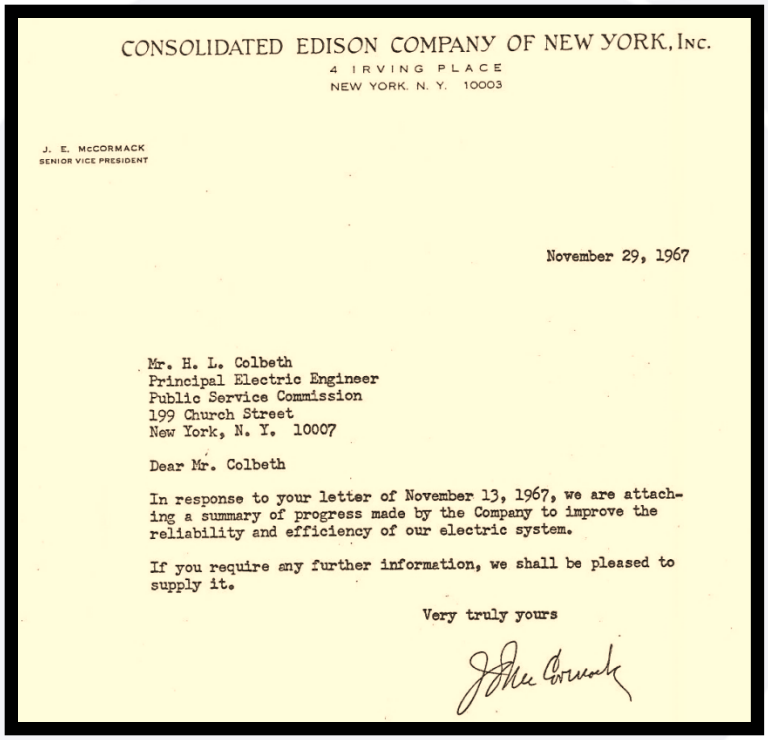
Dear Sirs:

As authorized by your letter of December 29, 1965, we have investigated the existing Northeast Interconnection, including additions and changes scheduled for completion before December, 1968.

We have analyzed system protection practices; simulated events that might cause serious system outages; recommended load shedding, system separation and other procedures to reduce the possibility of a widespread outage such as that of November 9, 1965; and presented design guidelines concerning the location and size of generating facilities and transmission system reliability.

9. Evenly distributed automatic load shedding should be provided for the entire NI system and should begin to take effect when the frequency falls to a value that indicates that separation from the interconnection has taken place.

25% in Two Stages



CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
4 IRVING PLACE
NEW YORK, N. Y. 10003

J. E. McCORMACK
SENIOR VICE PRESIDENT

November 29, 1967

Mr. H. L. Colbeth
Principal Electric Engineer
Public Service Commission
199 Church Street
New York, N. Y. 10007

Dear Mr. Colbeth

In response to your letter of November 13, 1967, we are attaching a summary of progress made by the Company to improve the reliability and efficiency of our electric system.

If you require any further information, we shall be pleased to supply it.

Very truly yours

J. E. McCormack

A load shedding system is presently being installed to disconnect load in outlying areas, having a minimal affect on the Transit Authority and high rise buildings. These facilities will automatically de-energize the feeders during system disturbances which result in declining system frequency. Indication will be received at the Energy Control Center of the areas where load has been shed. This system will permit automatic load relief of 1713 MW or 25% of the 1968 summer peak in two steps of 10% (by 59.0 HZ) and 15% (by 58.5 HZ). Installation in some areas will be completed in January, 1968 and the total program complete before the summer of 1968.

August 14, 2003

"All the News That's Fit to Print"

The New York Times

Late Edition
New York: **Today**, mostly sunny and hot. High 91. **Tonight**, clear and warm. Low 75. **Tomorrow**, partly sunny, humid, a late storm. High 87. **Yesterday**, high 89, low 75. Details, Page B11.

VOL. CLII . . . . No. 52,576 + Copyright © 2003 The New York Times NEW YORK, FRIDAY, AUGUST 15, 2003 ONE DOLLAR

POWER SURGE BLACKS OUT NORTHEAST, HITTING CITIES IN CANADA AND 8 STATES; MIDDAY SHUTDOWNS DISRUPT MILLIONS

OVERLOADED GRID

Buildings Are Evacuated and Hospitals Fill — Bush Plans Review

JAMES BARRON

A surge of electricity to western New York and Canada touched off a series of power failures and forced blackouts yesterday that left parts of at least eight states in the Northeast and the Midwest without electricity. The widespread failures provoked the evacuation of office buildings, stranded thousands of commuters and flooded some hospitals with people suffering in the stifling heat.

In an instant that one utility official called "a blink-of-the-eye second" shortly after 4 p.m., the grid that distributes electricity to the eastern United States became over-

August 14, 2003

2005 Energy Policy Act

Impact on NPCC Underfrequency Load Shedding

- NERC Standards become mandatory
- Effective June 18, 2007
- NPCC moves from Criteria, Guidelines, and Procedures to Directories
- Criteria A-03, Emergency Operations, Section 4.6 covered UFLS
  - 10% at 59.3 Hz
  - 15% at 58.8 Hz
  - Time delay reduced from 0.75 sec. to 0.30 sec. in August 2004
  - Moved into Directory 2

NPCC Directory 12

- Issued June 26, 2009
- Developed from
  - Directory 2 requirements
  - 2006 Assessment of Underfrequency Load Shedding (UFLS) Part III by SS-38 Working Group
- Original two stages extended to five

	Threshold Setting	Block Size	Total Operating Time
Stage 1	59.5 Hz	7 percent	300 ms
Stage 2	59.3 Hz	7 percent	300 ms
Stage 3	59.1 Hz	7 percent	300 ms
Stage 4	58.9 Hz	7 percent	300 ms
Stage 5 (anti-stall)	59.5 Hz	2 percent	10 s

NPCC Regional UFLS Standard

Version 1

- PRC-006-NPCC-1
- Regional Standard Authorization Request (RSAR) dated July 1, 2008
  - Intended to comply with NERC directive
- Approved by NPCC Board November 30, 2011
- Adopted by NERC Board February 9, 2012
- FERC granted final approval February 21, 2013

NERC Continent-wide UFLS Standard

Versions 1 and 2

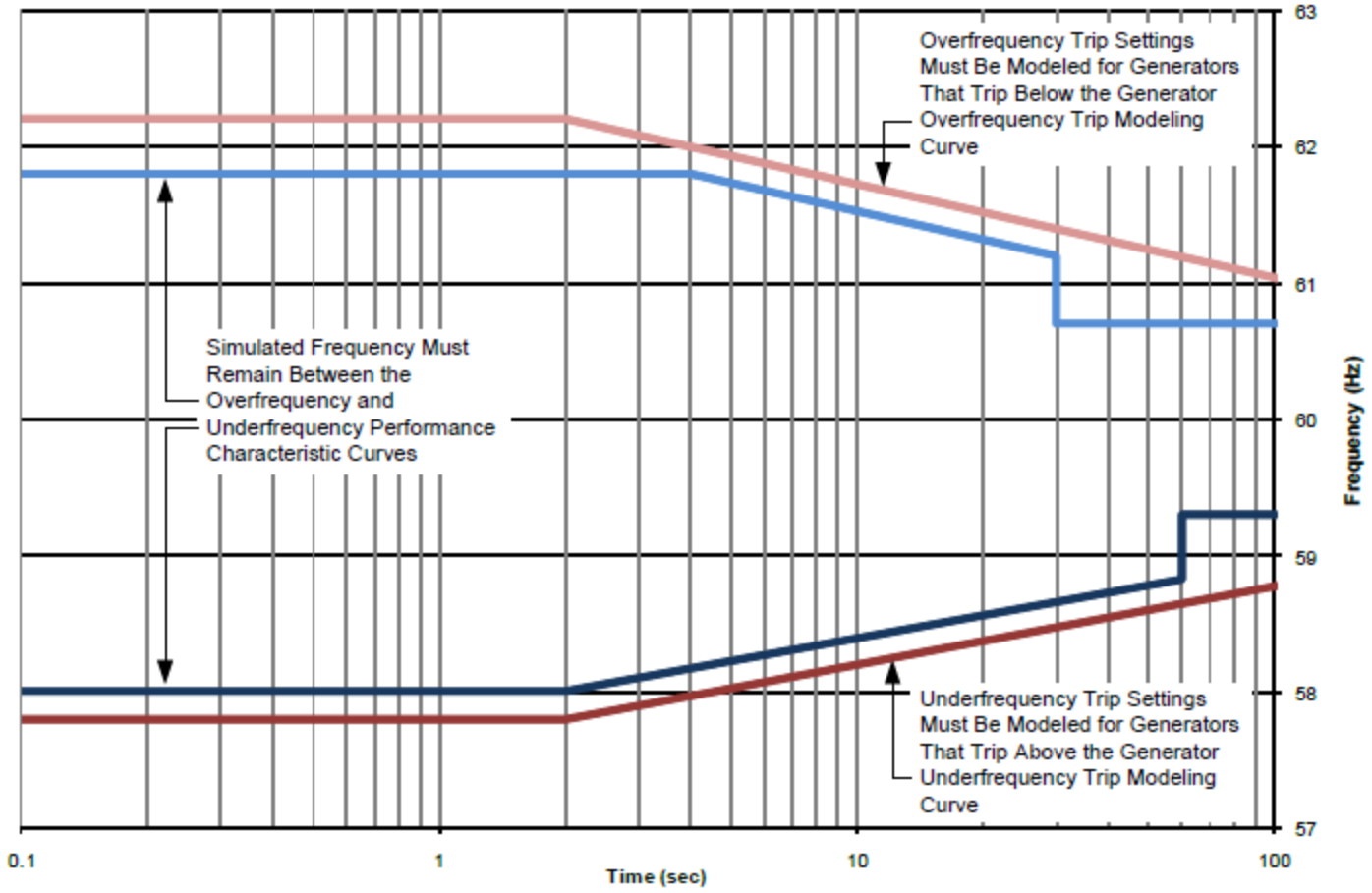
- PRC-006-1
- FERC granted final approval May 7, 2012
- NERC petitioned FERC on December 15, 2014 to replace PRC-006-1 with PRC-006-2
  - Follow through on Order 763 in which FERC called for a subsequent version dealing with corrective actions identified by Planning Coordinators
- NERC Board Adopted PRC-006-2 November 13, 2014
- FERC granted final approval March 4, 2015

NPCC Regional UFLS Standard

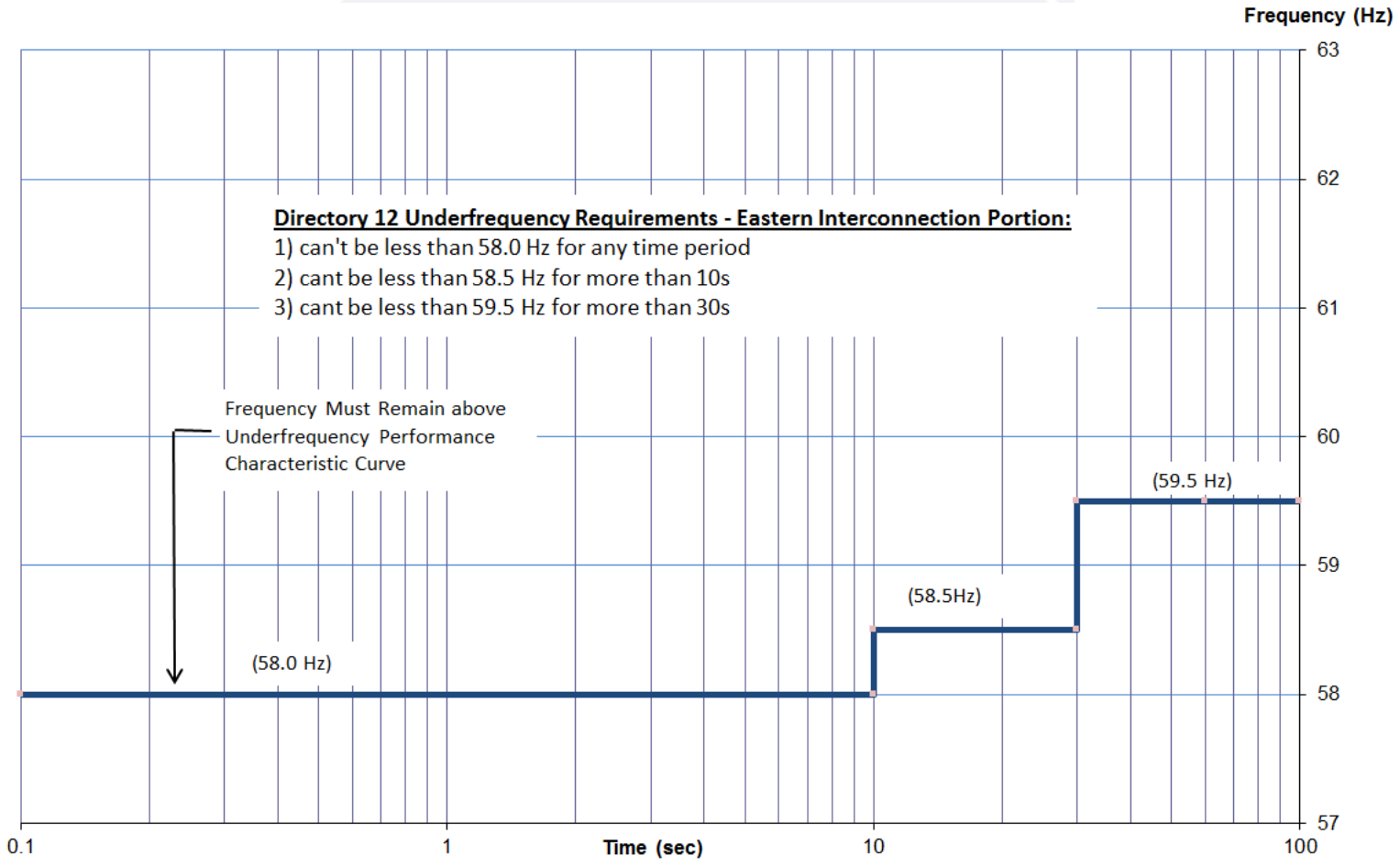
Version 2 – Presently being Drafted

- RSAR dated March 31, 2015
  - Potential revision or retirement of regional standard in light of the continent-wide standard
  - Compare PRC-024 requirements
    - Generator relay set points for ride-through during voltage and frequency excursions
  - New BES definition, effective July 1, 2014
  - Project 2014-01 on Dispersed Generation Resources
  - NERC's Paragraph 81 Project
    - FERC Order of March 15, 2012 on NERC's Find, Fix and Track Initiative
  - Elimination of redundancy / double jeopardy
  - Incorporation of Directory 12

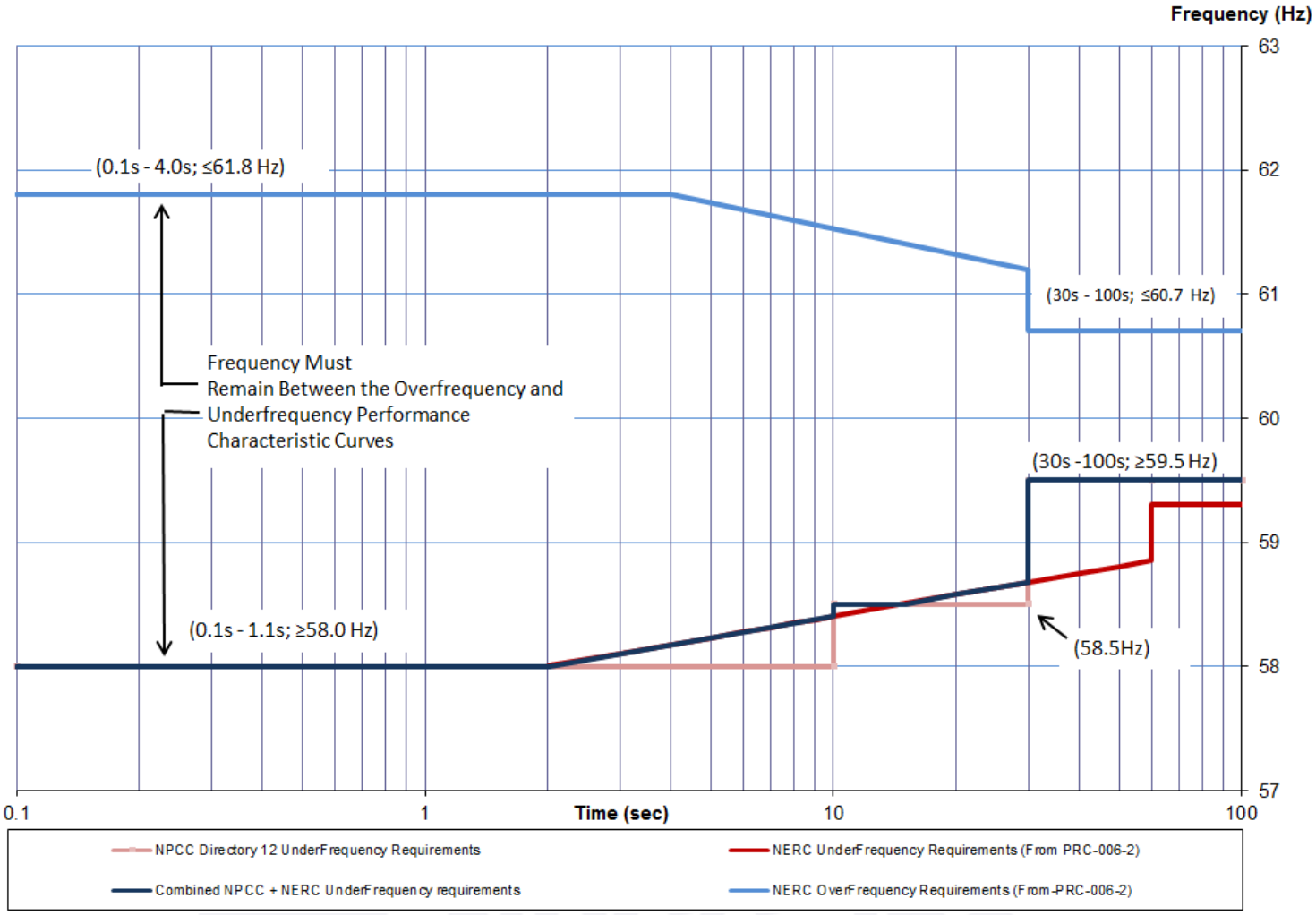
- NERC-PRC-006-2 UFLS Program Design Criteria:



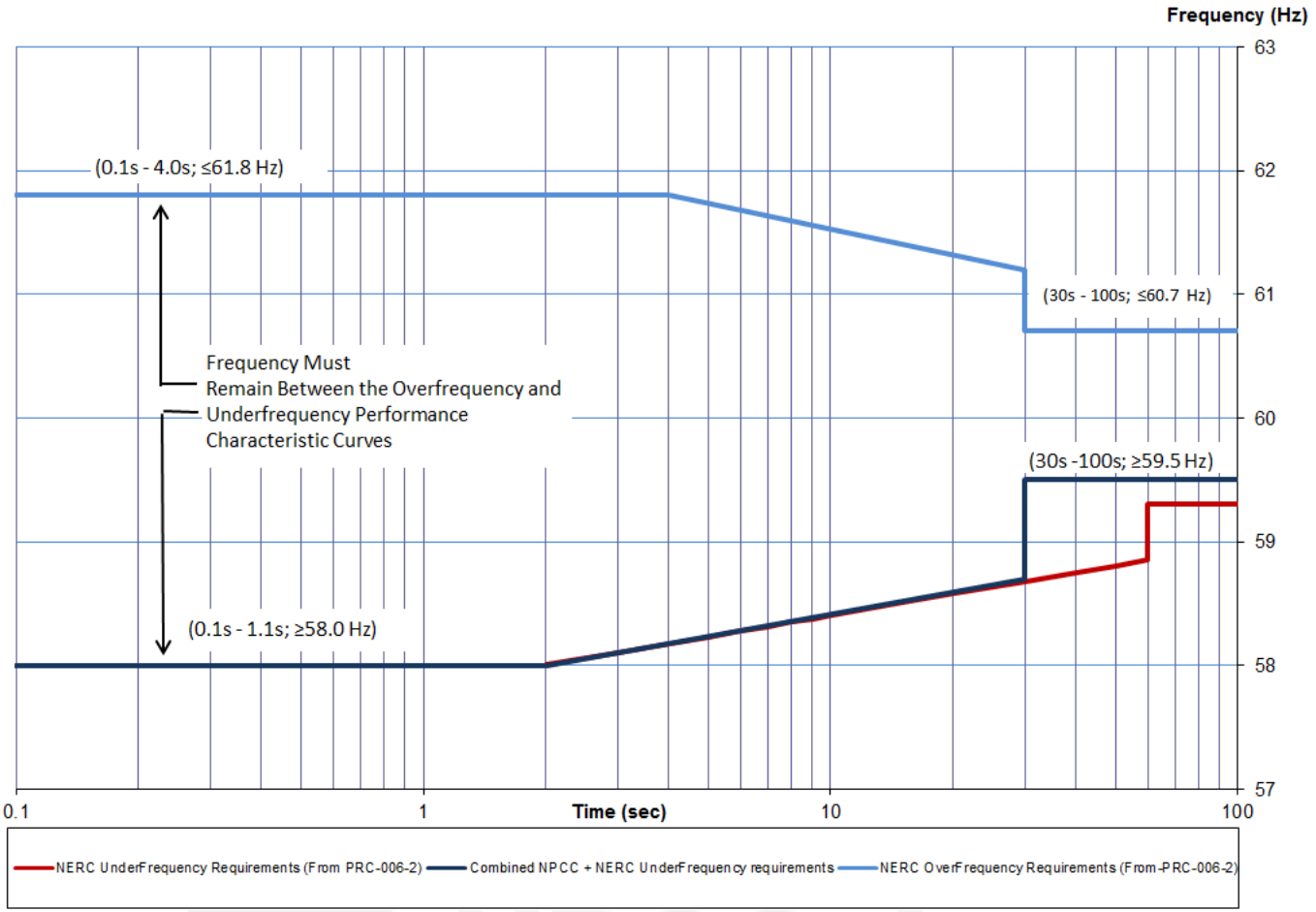
- NPCC Directory 12: UFLS Program Design Criteria



- Combined Curve (Directory 12 and NERC-006-2)



Combined Curve without 58.5 Hz Criterion from Directory 12



Proposed Change to PRC-006-NPCC-1: Incorporate Directory 12 UFLS Design Criteria

- Bring 59.5 Hz Recovery Criterion from Directory 12 into PRC-006-NPCC-2.

- Leave 58.0 Hz and 58.5 Hz Recovery criterion contained in Directory 12 out of PRC-006-NPCC-2. Does not add any increase in reliability.

- Enables retirement of Directory 12

Additional Change: UFLS on Island Basis

- All UFLS programs must be implemented on island basis.
- This was the original intent of PRC-006-NPCC-1.
- Clarified Language

Proposed Language Change: UFLS on Island Basis

"Whether implemented collectively or individually, the automatic UFLS program shall be **implemented on an island basis**. Each Distribution Provider and Transmission Owner shall provide the required load shedding amounts and frequency thresholds specified in the Attachment C, Tables 1 through 3, within each island identified per the NERC PRC Standard on UFLS."

Additional Change: Compensatory Load Shedding

- All generating units in need of compensatory load shedding must procure such load shedding in the same island as the subject generator exists.

- This was the original intent of PRC-006-NPCC-1.

- Clarified Language

Proposed Language change: Compensatory Load Shedding within same island as generator

"Have compensatory load shedding, as provided by a Distribution Provider or Transmission Owner that is adequate to compensate for the loss of their generator due to early tripping that is **within the UFLS island identified by the Planning Coordinator** in Requirement R2."

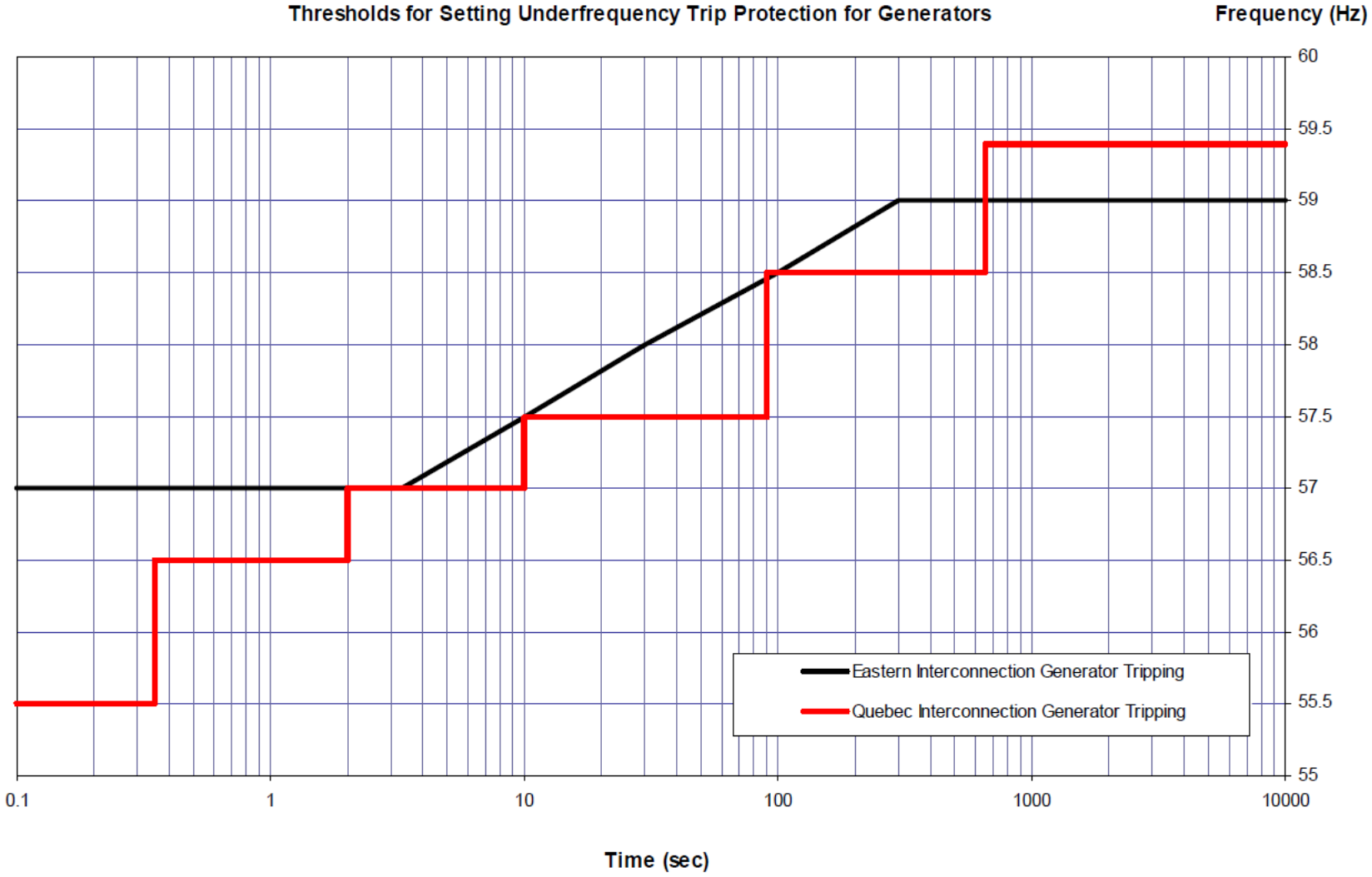
Additional Change: Figure 1 "On or Below Curve"

- Corrected Reference to Figure 1 in PRC-006-NPCC-1, concerning Generator tripping **"Below Curve".**

- Proposed Change: "Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, **on or below** the appropriate generator underfrequency trip protection settings threshold curve in Figure 1, except as otherwise exempted …"

Figure 1

Thresholds for Setting Underfrequency Trip Protection for Generators



Changes to UFLS Database Requirements

- Increased “Bus-by-Bus” data update requirement from once every year, to at least once every five years.

- Maintained “once every year” requirement for overall amounts and location of load shed at peak, the corresponding frequency threshold and time delay settings for each UFLS relay.

Clarification of Non-BES Generator Requirements

- Original language of PRC-006-NPCC-1 concerning requirements of Non-BES generators was unclear:

"Each Planning Coordinator shall, within 30 days of completion of its system studies required by the NERC PRC Standard on UFLS, identify to the Regional Entity **the generation facilities** within its Planning Coordinator Area necessary to support the UFLS program performance characteristics."

Proposed Clarifying language for Non-BES Generators

"Each Planning Coordinator shall, within 30 days of completion of its UFLS system studies, identify to the Regional Entity **all non-BES generation facilities, within its Planning Coordinator Area, that must not trip above the appropriate generator underfrequency trip threshold curve in Figure 1**, to support acceptable UFLS program performance ."

Additional Change – Allowance for reporting based on "Upstream Metering"

"Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be coincident with the entity's integrated hourly peak net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. **If there is no local metering of the load through said switches, the load may be calculated from measurements made at the nearest available metering, e.g., upstream metering on the distribution feeder that supplies the load to be shed.** "

Additional Change – Added Rationale Box for reporting based on "entity peak" instead of "system peak"

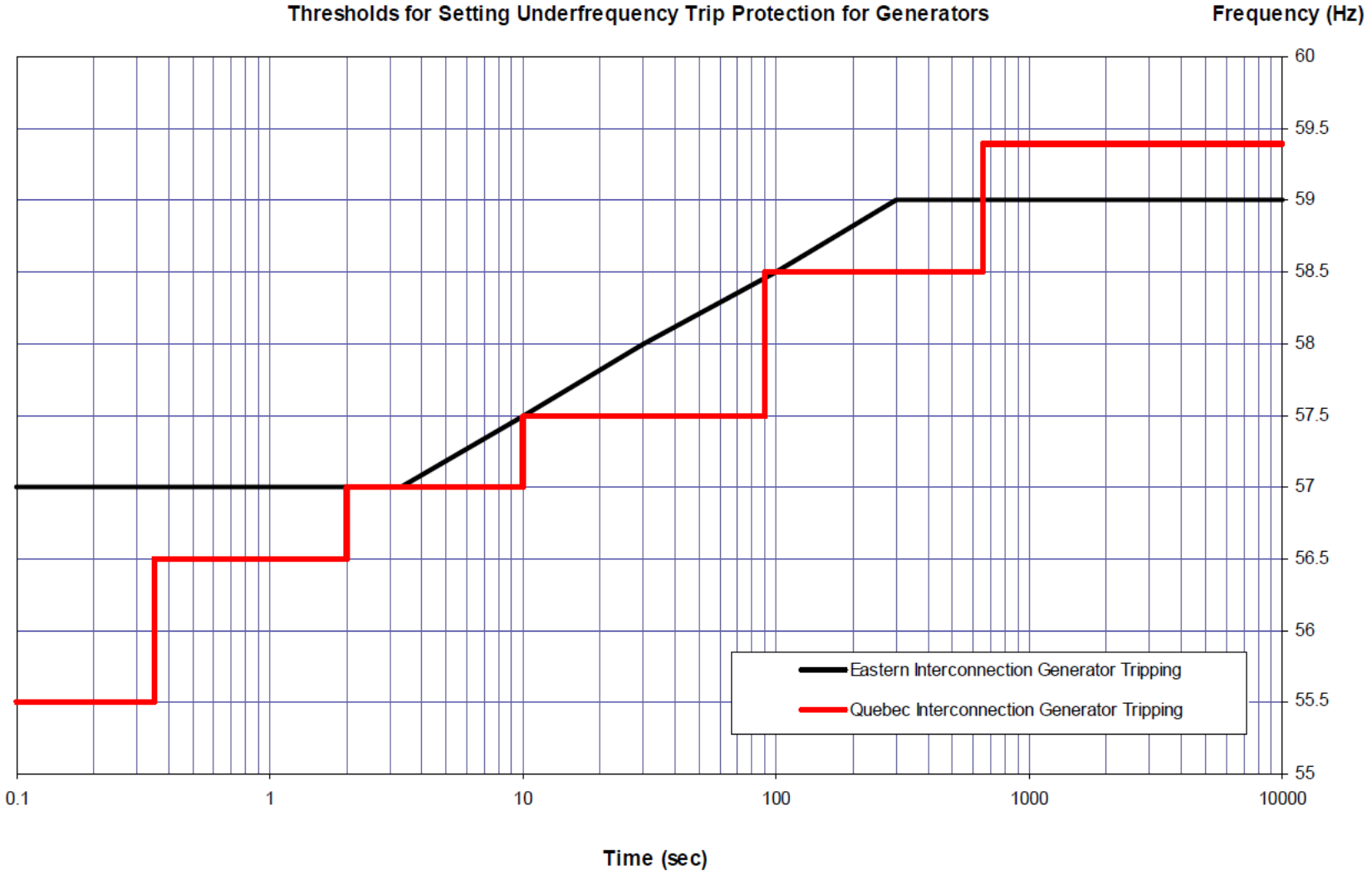
"Each Transmission Owner and Distribution Provider shall annually provide documentation, with no more than 15 months between updates, to its Planning Coordinator of the actual net Load that would have been shed by the UFLS relays at each UFLS stage. The actual net Load shall be **coincident with the entity's integrated hourly peak** net Load during the previous year, as determined by measuring actual metered Load through the switches that would be opened by the UFLS relays. If there is no local metering of the load through said switches, the load may be calculated from measurements made at the nearest available metering, e.g., upstream metering on the distribution feeder that supplies the load to be shed. "

Other Discussions – but no Changes: 1 Hz Margin for Generators on Figure 1 Curve

- Figure 1 has 57.0 Hz lower limit for generator tripping
- 57.0 Hz provides 1 Hz Margin from last stage of load shedding (58 Hz).
- NERC-PRC-006-2 has 57.8 Hz lower limit for Generator Tripping (0.2 Hz Margin)
- Drafting Team made decision to keep 1 Hz margin

Figure 1

Thresholds for Setting Underfrequency Trip Protection for Generators



Other Discussions – but no Changes: Treatment of DG in PRC-006-NPCC-2

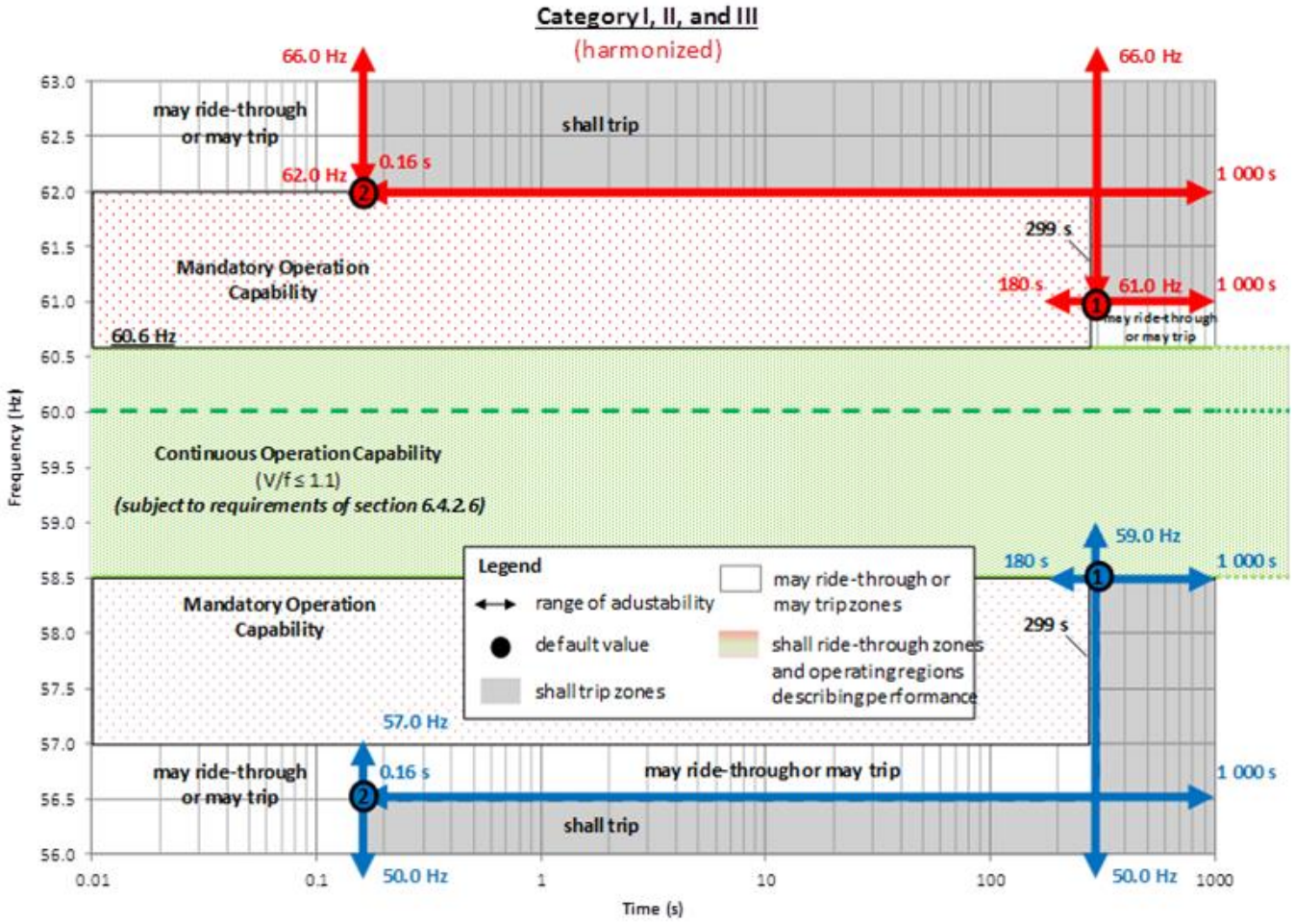
- Drafting Team discussed the possibility of adding a requirement in the standard to test sensitivity to forecasted Distributed Generation (DG) penetration.

- Drafting Team agreed that this is an important issue, bus should be left up to the SS-38 study process and scope.

Other Discussions – Changes to IEEE 1547

- IEEE is Revising standard 1547.
- Revised version of IEEE 1547 will mandate under/over frequency ride-through capability for Generation connected to the Distribution system.
- This will aid the UFLS program in NPCC.

Proposed IEEE 1547 Curve



Standard Drafting Team Timeline

- Kick-off Meeting June 3, 2016
- Industry representatives from
  - Quebec, Ontario, New England, and New York
  - Traditional transmission & distribution utilities
  - Independent System Operators
  - Generation
  - Compliance consultants
- Seven meetings to date
  - Most recently May 18-19, 2017
- Aiming to finalize draft by end of summer
- Quality check
- Severity levels to be refined

Questions

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

March 30, 2017

NPCC Full and General Members:

The ballot for approval of the revisions to the Quebec Variance in PRC-006-3 *Automatic Underfrequency Load Shedding* closed at 23:59 on March 24, 2017.

The results of the ballot were as follows:

Quorum: 79.59% of the Total Registered
Approval: 89.74%

One negative ballot was received without comments, therefore in accordance with the NPCC Standard Processes Manual, a recommendation for final Regional approval will be sent to the NPCC Board of Directors for consideration at their meeting on May 3, 2017.

Contingent upon the approval of the NPCC BOD, the proposal to adopt the revised variance in PRC-006-3 will be posted for a 45 day comment period by NERC, specifically related to NPCC's Standard development process. Upon receipt of any industry comments, responses to those comments will be posted on the NERC website. NERC will then submit the proposed standard, along with their endorsement, to the NERC Board of Trustees (BOT) for adoption. Upon adoption by the BOT, the standard will then be filed by NERC Legal with the FERC and applicable provincial authorities.

Voting was conducted electronically and the full ballot record may be viewed at:

https://www.npcc.org/Standards/SitePages/DevStandardDetail.aspx?DevDocumentId=123

Thank you for your participation.

Ruida Shu
Northeast Power Coordinating Council, Inc.
Senior Engineer, Reliability Standards and Criteria
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	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 1, Transmission Owners	**18**	**16**	**0**		**16**	**0**	**0**
Central Hudson Gas and Electric Corporation	1	1			1		
Central Maine Power Company	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Emera Maine	1						
Eversource Energy	1	1			1		
Hydro One Inc	1	1			1		
Hydro-Quebec TransEnergie	1	1			1		
Long Island Power Authority	1	1			1		
National Grid	1	1			1		
New Brunswick Power Corporation	1	1			1		
New Hampshire Transmission, LLC	1	1			1		
New York Power Authority	1	1			1		
New York State Electric & Gas Corporation	1						
Nova Scotia Power Inc.	1	1			1		
Orange and Rockland Utilities Inc	1	1			1		
Rochester Gas & Electric Corporation	1	1			1		
The United Illuminating Company	1	1			1		
Vermont Transco	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 2, Reliability Coordinators	**5**	**5**	**0**		**5**	**0**	**0**
Hydro-Quebec TransEnergie	1	1			1		
Independent Electricity System Operator	1	1			1		
ISO-New England, Inc.	1	1			1		
New Brunswick Power Corporation	1	1			1		
New York Independent System Operator	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 3, TDUs, Dist. And LSE	**20**	**16**	**0**		**14**	**0**	**2**
Braintree Electric Light Department	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Eversource Energy	1	1			1		
Groton Electric Light	1	1			1		
Hingham Municipal Lighting Plant	1	1			1		
Hydro One Inc	1	1			1		
Hydro Quebec Distribution	1	1			1		
Ipswich Municipal Light Department	1	1					1
Long Island Power Authority	1	1			1		
Marblehead Municipal Light Department	1	1			1		
National Grid USA	1	1			1		
New York Power Authority	1	1			1		
Orange and Rockland Utilities, Inc	1	1			1		
Princeton Municipal Light Department	1	1			1		
Shrewsbury Electric & Cable Operations	1	1			1		
Sterling Municipal Light Department	1						
Toronto Hydro Electric System Ltd.	1						
Vermont Electric Cooperative, Inc.	1						
Wakefield Municipal Gas and Light Department	1	1					1
Westfield Gas & Electric Light Department	1						

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 4, Generator Owners	**21**	**15**	**0**		**13**	**1**	**1**
Consolidated Edison Company of New York, Inc.	1	1			1		
Covanta Energy	1						
Dominion Resources, Inc.	1	1			1		
Dynegy, Inc.	1	1				1	
Entergy Nuclear Northeast, Inc	1	1			1		
Eversouce Energy	1	1			1		
Exelon Generation Company, LLC	1						
First Wind Operations & Maintenance	1						
International Power America	1						
Long Island Power Authority	1	1			1		
Massachusetts Municipal Wholesale Electric Company	1	1			1		
New York Power Authority	1	1			1		
NextEra Energy Resources, LLC	1	1			1		
NRG Energy Inc.	1	1			1		
Nova Scotia Power Inc.	1	1					1
Ontario Power Generation Inc.	1	1			1		
PSEG Fossil LLC	1						
Talen Energy Supply, LLC	1	1			1		
TransCanada	1	1			1		
Eastern Generation LLC	1						
Wheelabrator Westchester LP	1	1			1		

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 5, Marketers, Brokers, Aggragators	**13**	**10**	**0**		**9**	**0**	**1**
Brookfield Power Corporation	1	1			1		
Consolidated Edison Company of New York, Inc.	1	1			1		
Consolidated Edison Energy/Development	1	1			1		
Constellation New Energy, Inc.	1						
HQ Energy Marketing Inc.	1	1			1		
H.Q. Energy Services (U.S.) Inc.	1	1			1		
Long Island Power Authority	1						
Massachusetts Municipal Wholesale Electric Company	1	1			1		
Nalcor Energy	1	1					1
New York Power Authority	1	1			1		
Shell Energy North America	1	1			1		
Utility Services Inc.	1	1			1		
Windy Bay Power, LLC	1						

	1. Determine Quorum			2. Vote/Ballot Recording		
NPCC Registered Members	**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
	(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 6, State and Provincial Reg. and Govt. Authorities	**7**	**6**	**0**	**6**	**0**	**0**
Long Island Power Authority	1	1		1		
Maine Public Utilities Commission	1	1		1		
Massachusetts Attorney General	1	1		1		
New Hampshire Public Utilities Commission	1	1		1		
New York Power Authority	1	1		1		
New York State Department of Public Service	1	1		1		
Vermont Department of Public Service	1					

	1. Determine Quorum				2. Vote/Ballot Recording		
NPCC Registered Members		**In Attendance**	**By Proxy**		**Affirmative**	**Negative**	**Abstain**
		(denote w/ 1)	(denote w/ 1)		(denote w/ 1)	(denote w/ 1)	(denote w/ 1)
Sector 7, Sub Regional Rel. Councils, REs and Others	**14**	**10**	**0**		**7**	**0**	**3**
4g Technologies, LP	1						
Ascendant Energy Solutions, Inc.	1	1			1		
Energy Sector Security Consortium, Inc.	1						
ERLPhase Power Technologies	1	1			1		
International Business Machines Corporation	1						
McCoy Power Consultants, Inc.	1	1					1
Network & Security Technologies, Inc.	1	1					1
New York State Reliability Council, LLC	1	1			1		
Oxbow-Sherman Energy, LLC	1	1			1		
PLM, Inc.	1	1					1
Preti, Flaherty, Beliveau, and Pachios, LLP.	1	1			1		
Proven Compliance Solutions, Inc.	1	1			1		
SGC Engineering, LLC	1	1			1		
VIASYN, Inc.	1						

Determine Electronic Quorum

Sector	Sector Name	Total Registered	In Attendance	By Proxy	Total Represented	Sector % Attending
1	**Transmission Owners**	18	16	0	16	0.89
2	**Reliability Coordinators**	5	5	0	5	1.00
3	**TDUs, Dist. And LSE**	20	16	0	16	0.80
4	**Generator Owners**	21	15	0	15	0.71
5	**Marketers, Brokers, Aggragators**	13	10	0	10	0.77
6	**Customers- large and small**	7	6	0	6	0.86
7	**State and Provincial Reg. and Govt. Authorities**	14	10	0	10	0.71
		98	78	0	78	

Electronic Vote Quorum= at least 2/3 of the Total Registered

Quorum Present? **YES**

Determine if Motion or Item Passes

Sector	Sector Name	Total	Sector %	Affirmative		Negative		Abstain	Votes Cast	Sector has
		Registered	Attending	# of Votes	Fraction	# of Votes	Fraction	# of Votes	Total (- Abstentions)	Voted(1-Y, 0-N)
1	**Transmission Owners**	18	0.89	16	1.000	0	0.000	0	16	1
2	**Reliability Coordinators**	5	1.00	5	1.000	0	0.000	0	5	1
3	**TDUs, Dist. And LSE**	20	0.80	14	1.000	0	0.000	2	14	1
4	**Generator Owners**	21	0.71	13	0.929	1	0.071	1	14	1
5	**Marketers, Brokers, Aggragators**	13	0.77	9	1.000	0	0.000	1	9	1
6	**Customers- large and small**	7	0.86	6	1.000	0	0.000	0	6	1
7	**State and Provincial Reg. and Govt. Authorities**	14	0.71	7	1.000	0	0.000	3	7	1
	Totals	98		70	6.929	1	0.071	7	71	7

Sum of Affirmative/Number of Sectors that Voted
MUST BE AT LEAST 2/3 to pass

0.990

Did MOTION PASS?

PASS

REGIONAL STANDARDS COMMITTEE

Chairman:

Guy V. Zito
Assistant Vice President - Standards
Northeast Power Coordinating Council, Inc.
Tel. (212) 840-1070
Email: gzito@npcc.org

Co-Vice Chairman:

Si Truc Phan
Engineer – Reliability Standards & Operating Procedures
Reliability Coordinator
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Montreal, Québec, Canada H5B 1H7
Tel. (514) 798-1223 Ext. 8793610
Email: phan.si_truc@hydro.qc.ca

Co-Vice Chairman:

Michael Jones
Lead Analyst – FERC Compliance
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Waltham, Massachusetts 02451
Tel. (781) 907-2404
Email: michael.jones@nationalgrid.com

Sector 1 - Transmission Owners

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Alternate

The United Illuminating Company

Primary

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New York Independent System Operator

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Sector (3) - Transmission Dependent Utilities ("TDUs"); Distribution Companies and Load-Serving Entities ("LSEs")

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National Grid

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Sector (4) - Generator Owners

Consolidated Edison Company of New York, Inc.

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Entergy Services, Inc

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Alternate

Sector (5) - Marketers, Brokers and Aggregators

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Utility Services, Inc.

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Sector (6) – State and Provincial Regulatory and/or Governmental Authorities

New York Power Authority

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Sector 7 – Sub-Regional Reliability Councils, Customers and Other Regional Entities and Interested Entities

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Alternate

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

April 28, 2017

VIA ELECTRONIC FILING

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

RE: Errata to Petition of the North American Electric Reliability Corporation for Approval of Proposed Emergency Operations Reliability Standards
Docket No. RM17-12-000

Dear Secretary Bose:

On March 27, 2017, the North American Electric Reliability Corporation ("NERC") filed a Petition for approval of proposed Emergency Operations ("EOP") Reliability Standards ("Petition") with the Federal Energy Regulatory Commission ("Commission"). NERC submits this errata filing to correct an inadvertent exhibit error that has come to NERC's attention since original submission to the Commission. NERC hereby submits a replacement for Exhibit C, contained herein as Attachment 1.

Given the foregoing, NERC respectfully requests that the Commission consider this errata filing when issuing an order on the proposed EOP Reliability Standards to ensure a complete and correct record in Docket No. RM17-12-000.

Respectfully submitted,

/s/ Nina H. Jenkins-Johnston

Nina H. Jenkins-Johnston
Senior Counsel
North American Electric Reliability Corporation
1325 G St., NW, Suite 600
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(202) 644-8099 – facsimile
nina.johnston@nerc.net

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 28th day of April, 2017.

/s/ Courtney M. Baughan

Courtney M. Baughan
Senior Legal Assistant for the North American Electric Reliability Corporation

Attachment 1

Order No. 672 Criteria

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria.

1. **Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]**

The proposed Reliability Standards achieve specific reliability goals. Proposed Reliability Standard EOP-004-4 – Event Reporting, improves the reliability of the Bulk Electric System ("BES") by requiring the reporting of events by Responsible Entities. Proposed Reliability Standard EOP-005-3 – System Restoration from Blackstart Resources, ensure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection. Proposed Reliability Standard EOP-006-3 – System Restoration Coordination, ensures plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection. Proposed Reliability Standard EOP-008-2 – Loss of Control Center Functionality, ensures continued reliable operations of the BES in the event that a control center becomes inoperable.

The proposed Reliability Standards also satisfy an outstanding Commission directive from Order No. 749.

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[1] *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).

[2] Order No. 672 at PP 321, 324.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

The proposed Reliability Standards are clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard EOP-004-4, applies to Reliability Coordinators, Balancing Authorities, Transmission Owners, Transmission Operators, Generator Owners, Generator Operators, and Distribution Providers. Proposed Reliability Standard EOP-005-3, applies to Transmission Operators, Generator Operators, Transmission Owners identified in the Transmission Operators restoration plan and Distribution Providers identified in the Transmission Operators restoration plan. Proposed Reliability Standard EOP-006-3, applies to Reliability Coordinators. Proposed Reliability Standard EOP-008-2, applies to Reliability Coordinators, Transmission Operators, and Balancing Authorities. The proposed standards clearly articulate the actions that each entity must take to comply.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for each of the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment, as discussed further in **Exhibit E**. The assignment of the severity level for each VSL is consistent with the corresponding Requirement and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of

[3] Order No. 672 at P 322, 325.
[4] Order No. 672 at P 326.

similar penalties for similar violations. For these reasons, the proposed Reliability Standards include clear and understandable consequences in accordance with Order No. 672.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner. [5]

The proposed Reliability Standards contain Measures that support each Requirement by clearly identifying what is required to demonstrate compliance. These Measures help provide clarity regarding the manner in which the Requirements will be enforced, and help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[6]

The proposed Reliability Standards achieve the reliability goals effectively and efficiently in accordance with Order No. 672. Consistent with a Commission directive in Order No. 749, the proposed Reliability Standards improve upon the prior versions of the standards by: (i) ensuring strong planning, reporting, communication, and coordination across the Functional Entities; (ii) streamlining standards; and (iii) applying Paragraph 81 criteria, while making the standards more-Results-based.

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5 Order No. 672 at P 327.

6 Order No. 672 at P 328.

6. **Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.**[7]

The proposed Reliability Standards do not reflect a "lowest common denominator" approach. To the contrary, the revisions reflected in the proposed Standards provide significant benefits for the reliability of the Bulk-Power System. The requirements of the proposed Reliability Standards clarify the methodology requirements for Emergency operations, including the communication and coordination amongst reporting entities.

7. **Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.**[8]

The proposed Reliability Standards apply throughout North America and do not favor one geographic area or regional model.

8. **Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.**[9]

The proposed Reliability Standards have no undue negative effect on competition. The proposed Reliability Standards require the same performance by each applicable entity. The proposed standards do not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner.

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7 Order No. 672 at PP 329-330.
8 Order No. 672 at P 331.
9 Order No. 672 at P 332.

9. The implementation time for the proposed Reliability Standard is reasonable.[10]

The proposed effective dates for the proposed Reliability Standards are just and reasonable and appropriately balance the urgency in the need to implement the proposed Reliability Standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. NERC proposes an effective date for the proposed Reliability Standards that is the first day of the first calendar quarter that is twelve (12) months after the effective date of regulatory approval.

The proposed implementation periods are designed to allow sufficient time for the applicable entities to make any changes in their internal process necessary to implement proposed standards. The proposed effective dates are explained in the proposed Implementation Plans, attached as **Exhibit B**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standards were developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards.[12] **Exhibit G** includes a summary of the development proceedings, and details the processes followed to develop the proposed Reliability Standards. These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public. The initial and additional ballots achieved a quorum and exceeded the required ballot pool approval levels.

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[10] Order No. 672 at P 333.

[11] Order No. 672 at P 334.

[12] *See* NERC Rules of Procedure, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual).

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of the proposed Reliability Standards. No comments were received that indicated the proposed Reliability Standards conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other negative factors relevant to whether the proposed Reliability Standards are just and reasonable were identified.

[13] Order No. 672 at P 335.
[14] Order No. 672 at P 323.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Balancing Authority Control, Inadvertent Interchange, and Facility Interconnection Reliability Standards	)))	Docket No. RM16-13-000

RESPONSE OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION TO DATA REQUEST

The North American Electric Reliability Corporation ("NERC") hereby submits its response to the Federal Energy Regulatory Commission's ("FERC" or the "Commission") data request ("Data Request"), issued March 7, 2017 in the above-captioned docket, seeking additional information in response to NERC's petition for approval of Reliability Standards BAL-005-1 and FAC-001-3 and of the retirement of currently-effective Reliability Standards BAL-005-0.2b, BAL-006-2, and FAC-001-2. The Commission's Data Request seeks additional information regarding the proposal to eliminate Requirement R15 from current Reliability Standard BAL-005-0.2b, which requires Balancing Authorities ("BAs") to have and to periodically test backup power supplies at primary Control Centers and other critical locations to ensure continuous operation of Automatic Generation Control and vital data recording equipment during loss of normal power supply.

Specifically, the Commission requested further information from BAs, Reliability Coordinators ("RCs"), and/or Transmission Operators ("TOPs") regarding the following:

1. Does the identified entity have backup power supplies at its primary control center(s), its backup control center(s) and other critical locations? Briefly describe what types of backup power supplies are in each location, how long these supplies will provide power, what level of service the backup power supplies support, and how the entity has determined what locations warrant backup power supplies and the performance requirements for those supplies.

2. For each location identified above, how often and when were backup power supplies tested, including testing of switchover (i.e., from primary power supply to backup power supply), during 2016? What are the procedures for testing, and how are the tests documented?

Consistent with the Commission's request, NERC collected data from a representative sample of nine entities registered with NERC as a BA, RC, and/or TOP regarding their current practices for backup power supplies at Control Centers and other critical locations. As discussed below, each of the entities surveyed had backup power supplies at their primary and backup Control Centers and, in some cases, other locations such as data centers, power plants, and other types of operations centers. The surveyed entities indicated they use backup generators and batteries to provide power to these locations when their normal power supply is lost. The overwhelming majority of surveyed entities indicated they perform run testing of their backup power supplies on a monthly basis. In some cases, the entities also performs switchover (or transfer) testing on a monthly basis while others perform such testing at longer intervals (e.g., annually).

This response is organized as follows: Section 1 discusses the representative sample of registered entities selected to share information; Section 2 discusses the responses to the Commission's first question regarding location and type of backup power supplies; and Section 3 discusses the responses to the Commission's second question regarding testing of backup power supplies.

1. Representative Sample of Registered Entities

As noted above, NERC collected data from nine entities registered as BAs, RCs, and/or TOPs. Of the nine entities, two are registered as a BA, RC, and TOP; five are registered as both a BA and TOP; one is registered as a TOP but neither a BA nor RC; and one is registered as a BA but neither a RC nor TOP. Further, to get a representative sample of entities, NERC collected data from at least one entity in each Regional Entity footprint. The sample of entities also reflects a

combination of Independent System Operators/Regional Transmission Organizations, investor-owned utilities, and electric cooperatives. Given the diversity of surveyed entities, the information provided herein should be representative of current practices throughout the industry. As discussed below, each of the surveyed entities have sufficient backup power supplies and test these supplies on a regular basis in accordance with their internal policies.

2. Location and Types of Backup Power Supplies

a. Location

As noted above, each of the surveyed entities reported that they have backup power supplies at both their primary and backup Control Centers. The entities reported that backup power supplies at these locations was a matter of sound operating practices to ensure continued operations in the event their main sources of power are lost. A number of entities reported that backup power supplies at their primary and backup Control Centers were installed prior to the effective date of NERC's mandatory Reliability Standards and, because of the importance of having backup power at Control Centers, would not change their practices if the Commission approves the elimination of Requirement R15 of BAL-005-0.2b.

Entities reported that their decisions as to where to locate backup power supplies were based on determination as to where such supplies were most critical for continued operations. Based on such determinations, in addition to their Control Centers, surveyed entities also identified other facilities for which backup supplies are used, as follows:

- One of the entities reported that it had backup power supplies for its data center, which was not located in the same buildings as its primary or backup Control Centers.
- Two of the surveyed entities reported that they also had backup power supplies to service certain corporate facilities. One of those entities explained that certain corporate facilities were chosen for backup power supply, in part, to provide senior management the ability to address emergency situations.

- Another entity reported providing backup power supplies to its operations center that houses its cyber and physical security operations.
- Lastly, one of the surveyed cooperatives reported that it has backup power supplies at its primary base load generation facility and a peaking plant.

b. Type

The surveyed entities identified two types of backup power supply sources at their primary and backup Control Centers: (1) backup generators; and (2) uninterruptible power supply ("UPS") batteries. Additionally, two entities noted that they have power feeds from separate utility providers to create redundancies in their main sources of power. As the data request focused on backup power supplies, other entities may have power feeds from separate utilities but did not report it to NERC as part of the date request. Attachment 1 hereto provides details on the backup power supplies, including the length of time these sources provide power. As provided in Attachment 1, the surveyed entities reported adequate levels of backup power supplies to provide for continued operations in the event they lose their normal source of power.

3. Testing of Backup Power Supplies

Each of the surveyed entities reported that they regularly test their backup power supplies in accordance with written procedures. The overwhelming majority of surveyed entities indicated they perform run testing of their backup power supplies on a monthly basis. In some cases, entities also perform switchover (or transfer) testing on a monthly basis while others perform such testing at longer intervals (e.g., annually). Each of the entities confirmed that they performed run and/or switchover testing in 2016 in accordance with their written procedures. Attachment 2 hereto provides additional detail on the testing practices of the surveyed entities.

4. Conclusion

NERC respectfully requests that the Commission consider this additional information and approve proposed Reliability Standards BAL-005-1 and FAC-001-3 and the retirement of currently-effective Reliability Standards BAL-005-0.2b, BAL-006-2, and FAC-001-2.

Respectfully submitted,

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Date: April 6, 2017

Attachment 1

Attachment 1

The following chart provides details on the backup power supplies reported by each surveyed entity, including the length of time these sources provide power.

Entity Functions	Primary Control Center	Backup Control Center	Other Locations
Respondent 1 - BA - TOP	One backup generator (2 MW) - 65 hours of supply - Generator serves entire building (primary Control Center, distribution operations, corporate incident command center…etc.), Also equipped with a UPS system to support critical load while the generator starts and comes on line.	One backup generator (2 MW) - 74 hours of supply - Generator serves only critical loads in building (excludes non-essential workstations, conference rooms, - corridor outlets, and non-essential lighting Also equipped with a UPS system to support critical load while the generator starts and comes on line.	Data Center and Integrated Operations Center (cyber and physical security operations): - One generator (1.25 MW) - 58 hours of supply - Serves entire building
Respondent 2 - BA - TOP	One diesel Generator - 100 hours of supply before refueling - Provides backup power to server room and dispatch, HVAC serving critical areas, and lighting in critical areas Battery (UPS) - Two 100 kVA batteries Rated to provide power at full load for one hour and currently running at 25% overall capacity - Designed to keep EMS workstations and critical corporate workstations running Respondent 2 has multiple power feeds from different utilities	One diesel generator - 40 hours of supply before refueled - Serves critical load Battery (UPS) - One 80 kVA batter - Rated to provide power at full load for a one hour and is currently running at 30% overall capacity - Designed to keep all Control Center infrastructure running	- Some corporate facilities (e.g., boardroom) have backup power to facilitate upper management meetings to address emergency situations

Entity Functions	Primary Control Center	Backup Control Center	Other Locations
Respondent 3 - BA - TOP	Generators - Two 2,100 kW diesel generators (4,200 kW total) - Respondent 3 reported enough fuel on site for 72 hours and has access to delivery of additional fuel to run continuously. - Supplies critical facilities (control rooms, data centers, and network rooms) Battery - Two trains of two 675 kW UPS modules (total capacity of 2700 kW)	Generators - One 1000 kW diesel generator - Respondent 3 reported enough fuel on site for 72 hours and has access to delivery of additional fuel to run continuously. Battery - 320 kW UPS module	n/a
Respondent 4 - BA - RC - TOP	Generators - 50 hours of service - Respondent 4 reported they have emergency fuel contract in place to service generators Battery (UPS) - UPS battery could supply power for 25 minutes under full load	Generators - 50 hours of service - Respondent 4 reported they have emergency fuel contract in place to service generators Battery (UPS) - UPS battery could supply power for 25 minutes under full load	n/a
Respondent 5 - BA - TOP	Generator - 400 kW diesel generator - Services entire Control Center building - Fuel tank supplies power for 15-16 hours and Respondent 5 has resupply contract with local delivery sources to supply fuel indefinitely	Generator - 29.6 MW – fuel oil - Serves entire Control Center building - Full tank supplies approximately 17 hours with resupply services in place with local delivery to supply fuel indefinitely	Respondent 5 also has backup generators at its corporate headquarters (24 hours of support before resupply), its primary base load power plant (48 hours of support before resupply), and a peaking Plant (23 hours of support before resupply)

Entity Functions	Primary Control Center	Backup Control Center	Other Locations
Respondent 6 - BA - RC - TOP	Three generators - Two 1500 kV generators for critical load (control room, data centers, etc.) - One 750 kV for non-critical elements (building lights, etc.) Battery - two 750 kVA UPS modules - Provide redundant conditioned power Respondent 6 reported that it has multiple power feeds from separate utility providers Reported a total of five days of backup power	Three generators - Two 1500 kV generators for critical load (control room, data centers, etc.) - One 600 kV generator for non-critical elements (building lights, etc.) Battery - two 750 kVA UPS modules - Provide redundant conditioned power Respondent 6 reported that it has multiple power feeds from separate utility providers Reported a total of five days of backup power	n/a
Respondent 7 - TOP	Generator - Supplies backup power indefinitely with adequate fuel supply - Serves critical load Battery - UPS module - Supplies power for 22 minutes - In place to supply power until generators start	Generator - Supplies backup power indefinitely with adequate fuel supply - Serves critical load Battery - UPS module - Supplies power for 20 minutes - In place to supply power until generators start	n/a

Entity Functions	Primary Control Center	Backup Control Center	Other Locations
Respondent 8 - BA - TOP	Generator - Service entire facility where Control Center is located - Dual back-up generators for redundancy - Approximately 20 days of fuel on site Battery (UPS) - In place for all critical loads - Designed to provide 2 hours of supply until backup generators start running	Generator - Service entire facility where Control Center is located - Dual back-up generators for redundancy - Approximately 20 days of fuel on site Battery (UPS) - In place for all critical loads - Designed to provide 2 hours of supply until backup generators start running	n/a
Respondent 9 - BA	Generator - Diesel unit with 1750 kW capacity - 22 hours of supply on one tank with additional fuel supply close by - Serves entire Control Center building Battery - 2 400 kVA UPS devices - Supplies power for 8-10 minutes at full load - Serves entire Control Center building	Generator - Diesel unit with 500 kW capacity - 24 hours of supply on one tank with additional fuel supply close by - Serves entire Control Center building Battery - 120 kVA UPS devices - Supplies power for 8-10 minutes at full load - Serves entire Control Center building	n/a

Attachment 2

Attachment 2

The following chart provides details on the testing of backup power supplies.

Entity	Testing Type and Timeframe	Procedures and Documentation
Respondent 1 - BA - TOP	Performs monthly run testing of back power supply for all locations with backup power supply, including two hour load bank testing (at 100% for one hour and 80% for one hour). Performs annual switchover testing for all locations with backup power supply to simulate a loss of utility power to allow automatic operation of generator, UPS and HVAC systems.	Testing performed according to written procedures. Testing is documented in a Method of Procedure document and the test report summarizing the test results.
Respondent 2 - BA - TOP	Performs monthly run testing of its backup generators and UPS batteries at all locations. Backup power supply run with all load for an hour. Performs annual switchover testing for generators and batteries at all locations with backup power supply. For batteries, a vendor provides maintenance on an annual basis. Batteries manufacturer performs maintenance twice a year.	Testing performed according to written procedures. Testing is documented in logs.
Respondent 3 - BA - TOP	For its generators, performs run testing and preventative maintenance at all locations on a quarterly basis; changes oil and filter on an annual basis, and performs a full load bank test annually. For battery backup, performs quarterly maintenance tests and inspections. Performs switchover testing of generators and batteries at all locations at least once every three years.	Testing performed according to written procedures. Testing documented through change management process and test results are captured in trend logs on the building automation system that monitors backup power supplies.
Respondent 4 - BA - RC - TOP	Performs run testing every two weeks for 30 minutes. Performed switchover testing on a monthly basis.	Testing performed according to written procedures. Testing is documented in SCADA system event log as well as through a computerized maintenance management system.

Entity	Testing Type and Timeframe	Procedures and Documentation
Respondent 5 - BA - TOP	Performs run testing for the backup generators at its primary Control Center and corporate headquarters for one hour on a monthly basis. Performs run testing for the backup generator at its backup Control Center every other month. Performs switchover testing at its primary Control Center and corporate headquarters on a monthly basis but at its backup Control Center every three years.	Testing performed according to written procedures. Testing documented on Operational Record and Emergency Generator Check Sheet
Respondent 6 - BA - RC - TOP	Perform run testing (30 minute load test) on a monthly basis. Performs switchover testing on a monthly basis.	Testing performed according to written procedures. Testing documented through log sheets in Work Order Maintenance System
Respondent 7 - TOP	Performs testing of the UPS batteries on a semi-annual basis and the backup generators on a monthly basis. There are three levels of inspection/testing for the generators, one of which includes an actual transfer or switchover.	All tests are conducted by contractors and the results documented on an Inspection and/or Test Report. Records are reviewed and retained on-site.
Respondent 8 - BA - TOP	Performs testing of backup power supplies at each location at least every month. The test procedures include switchover and a test of each configuration.	Testing performed according to written procedures. Testing documented in a work management system.
Respondent 9 - BA	Performs (one hour) run testing for backup generators at all locations on a monthly basis. Performs run testing for UPS battery annual basis with switchover test. Performs annual switchover testing at all locations. Performs annual full load testing for generators at all locations.	Testing performed according to written procedures. Testing documentation stored on in database and with copies from vendors.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

March 31, 2017

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20426

Re: NERC Standards Report, Status and Timetable for Addressing Regulatory Directives, and Periodic Review of Reliability Standards
Docket No. RR09-6-003

Dear Secretary Bose:

The North American Electric Reliability Corporation ("NERC") hereby submits the 2017 NERC Standards Report, Status and Timetable for Addressing Regulatory Directives (the "Directives Report") in accordance with Section 321.6 of the NERC Rules of Procedure ("ROP").[1] This annual report summarizes the progress made, and plans for addressing the Reliability Standards-related directives issued by applicable governmental authorities.

1. Report on Regulatory Directives

Section 321.6 of NERC's ROP requires NERC, on or before March 31 of each year, to file a report with applicable governmental authorities on the status and timetable for addressing each outstanding regulatory directive. Attached hereto is the Directives Report for 2017. As discussed in the Directives Report, since the Commission-certified NERC as the Electric Reliability Organization, the Commission has issued 81 orders that contain 832 directives related to NERC Reliability Standards. As of March 2017, NERC has addressed 798 or 95.9% of the 832 directives and continues to make substantial progress in addressing the remaining 30 directives. Since the 2016 Directives Report, the Commission has issued five orders containing 13 directives. In the past year, NERC has also filed petitions with the Commission addressing 23 outstanding directives. The 2017-2019 Reliability Standards Development Plan ("RSDP") provides a plan to address the remainder of the standards-related directives.

NERC's annual RSDP establishes priorities related to Reliability Standards to help ensure that those issues that most directly impact Bulk-Power System reliability are addressed first. Directives to create new or modify existing Reliability Standards are assigned to existing or future development projects that are

[1] The Federal Energy Regulatory Commission ("FERC" or "Commission") approved Rule 321 on March 17, 2011 in the above captioned docket. *Order on Compliance Filing*, 134 FERC ¶ 61,216 (2011).

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prioritized by the NERC Standards Committee and reflected in the RSDP. The 2017-2019 RSDP was filed with the Commission on December 16, 2016.[2]

The attached Directives Report includes the following appendices to aid in understanding the specific regulatory directives received to date and the standard development projects assigned to address those directives:

- Appendix A – Regulatory Orders Containing Directives
- Appendix B – Directives Listed by Commission Order
- Appendix C – Remaining Directives to be Addressed

Please contact me if you have questions or need additional information.

Respectfully submitted,

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[2] NERC's 2017-2019 RSDP is accessible at the following link: http://www.nerc.com/FilingsOrders/us/NERC%20Filings%20to%20FERC%20DL/2017-2019%20RSDP%20FERC_Filing.pdf.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Standards Report

Status and Timetable for Processing Regulatory Directives

March 31, 2017

RELIABILITY | ACCOUNTABILITY

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Chapter 1 – Introduction

North American Electric Reliability Corporation ("NERC") Reliability Standards consist of performance-, risk-, and competency-based mandatory reliability requirements that collectively provide a defense-in-depth structure for planning, operating, and protecting the reliability of the North American Bulk-Power System (BPS). NERC Reliability Standards hold all users, owners, and operators of the BPS accountable for meeting specific reliability-related requirements and are an essential tool in helping to ensure that the North American BPS is operated, maintained, and protected in a manner that supports all other services essential to health, safety, and financial security.

NERC Reliability Standards are developed pursuant to the NERC Standards Process Manual, which is incorporated into the NERC Rules of Procedure ("ROP"). NERC staff works with the NERC Standards Committee, industry experts, and applicable regulatory and governmental authorities in the United States and Canada to create or modify Reliability Standards. Under Section 215 of the Federal Power Act ("FPA"), the Federal Energy Regulatory Commission ("FERC" or the "Commission") may direct NERC to develop new or modify existing Reliability Standards.

Section 215(d)(5) of the FPA states that "the Commission, upon its own motion or upon complaint, may order the Electric Reliability Organization to submit to the Commission a proposed reliability standard or a modification to a reliability standard that addresses a specific matter if the Commission considers such a new or modified reliability standard appropriate to carry out this section."

Section 321.6 of NERC's ROP requires NERC to file a report with applicable governmental authorities on the status and timetable for addressing each outstanding regulatory directive. This annual report is submitted in fulfillment of this ROP requirement.

Executive Summary

Since the Commission certified NERC as the Electric Reliability Organization ("ERO") for the United States in 2006, the Commission has issued 81 orders containing 832 directives related to NERC Reliability Standards. This report provides the status of each directive and updates the March 31, 2016 report to include directives addressed from April 1, 2016 through March 31, 2017. This report includes FERC directives pertaining to information or data collection (non-standards related directives). Historically these directives were tracked along with directives related to Reliability Standards, but were not reported in the annual report. Since April 1, 2016, the Commission has issued five orders that contain 13 directives.[1]

[1] The three orders are:

1. *Revised Critical Infrastructure Protection Reliability Standards,* Order No. 829, 156 FERC ¶ 61,050 (2016). This order contains 1 directive.
2. *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events,* Order No. 830, 156 FERC ¶ 61,215 (2016). This order contains 6 directives.
3. *Order Approving Reliability Standards,* 156 FERC ¶ 61,207 (2016). This order contains 1 directive.
4. *Availability of Certain North American Electric Reliability Corporation Databases to the Commission,* Order No. 824, 155 FERC ¶ 61,275 (2016). This order contains 1 directive.

Of the 832 directives that FERC has issued since NERC was certified as the ERO, 32 relate to Regional Reliability Standards, 53 were considered "not standards related", and 41 were withdrawn in FERC Order No. 788.[2] The majority of standards-related directives (435) were issued in eight orders in 2007. There were 123 directives issued in 2008, 62 issued in 2009, 67 issued in 2010, 32 issued in 2011, 18 issued in 2012, 42 issued in 2013, 10 issued in 2014, 26 directives issued in 2015, and 17 directives in 2016. As of the date of filing, FERC has issued four directives in 2017.

Further, of the 832 total directives, NERC has addressed 798 directives or 95.9% and continues to make substantial progress in addressing the remaining 30 directives (see Appendix C). There are 16 outstanding directives being addressed in current projects, 3 relating to Regional Reliability Standards, and 7 are non-standards related (data gathering, registration, or research related).

Since the 2016 report, NERC filed petitions with the Commission addressing 23 outstanding directives.

Background

This is the eighth annual directives report submitted to the Commission. Each year, NERC strives to improve the directives report based on increased communication with the Commission, within NERC, and with industry stakeholders.

NERC processes directives in a manner consistent with its ROP, including Appendix 3A (the Standard Processes Manual). Specifically, when the Commission issues any order or rule, NERC staff reviews the order/rule to, among other things, identify any directives within the order/rule related to standards development. Any such directives are assigned a unique, five digit reference number. These directives are then verified for accuracy with FERC staff and tracked through completion.

Once a standard has been adopted by the NERC Board and filed with the applicable regulatory authorities, the status of all the directives associated with that project are marked "filed" in NERC's records, which are provided to FERC staff. If, after filing for regulatory approval, a regulatory authority declares that a directive has not been adequately resolved, a new directive is identified.

It is the responsibility of NERC and the standard drafting teams to work with industry stakeholders to respond to the Commission directives, either by addressing the directive as issued or providing an equally efficient and effective solution supported by a technical justification. Since 2013, NERC and FERC increased FERC staff's participation in the standards development process, particularly at the early stages of the process, allowing the drafting team to consider FERC staff's feedback in a productive and timely manner.

Also in early 2013, NERC set a goal to complete the 191 directives relating to standards that had not been addressed and continue to address any new directives. The plan for completing directives through standards development projects is set forth in the Reliability Standards Development Plan

5. *Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard,* Order No. 835, 158 FERC ¶ 61,030 (2017). This order contains 4 directives.

[2] *Electric Reliability Organization Proposal to Retire Requirements in Reliability Standards*, Order No. 788, 145 FERC ¶ 61,147 (2013).

(RSDP), which is adopted by the NERC Board of Trustees and filed with FERC. The annual RSDP provides a plan to address the remainder of the standards-related directives by the end of 2017, with the exception of one directives that cannot be addressed through a standards development project.[3]

NERC also reports its progress in addressing these directives to the NERC Standards Oversight and Technology Committee on a quarterly basis. These reports are also available to FERC staff, and NERC staff continues to meet with FERC staff to achieve a consensus on the number of outstanding directives.

[3] The one directive is open-ended: See Appendix B, S-Ref 10917.

Chapter 2 – Status of Directives

Directives Issued by the Commission

On July 20, 2006, the Commission issued an order certifying NERC as the ERO in accordance with Section 215 of the FPA. Following approval by the Commission, NERC's initial set of Reliability Standards became mandatory and enforceable within the United States on June 18, 2007. Since January 1, 2007, the Commission has issued orders containing 832 directives related to NERC Reliability Standards. NERC has addressed 798 directives in its standards development process, leaving 30 to be resolved.

Appendix A to this report contains a chronological list of Commission orders that contain standards-related directives. Appendix B contains a complete list of the directives associated with each of the Commission orders identified in Appendix A.

Tabulated by year of issuance, the number of directives issued and addressed since 2007 is provided in Table 1:

Table 1: Directives by Year

Year	Issued	Addressed
2007	435	40
2008	123	99
2009	62	102
2010	67	49
2011	32	121
2012	18	31[4]
2013	42	143
2014	10	104
2015	26	80
2016	13	23
2017 (through March 31, 2017)	4	6
Total	832	798

[4] One directive that was previously indicated as being resolved in 2012 was withdrawn by FERC Order 788 and, in turn, was moved to 2013.

Chapter 3 – Timeline for Processing Outstanding Directives

One of NERC's core responsibilities is to ensure the reliability of the Bulk-Power System by developing effective Reliability Standards that are clear, consistent, and technically sound. All Bulk-Power System owners, operators, and users must comply with these standards, which define the requirements for planning, operating, and protecting the North American electrical grid so that widespread cascading outages, uncontrolled separations, and blackouts do not occur. The success of NERC standards development depends on active participation from the industry on drafting teams, during comment periods and in ballot pools. It is the users, owners and operators of the Bulk-Power System who both develop NERC's mandatory Reliability Standards and implement them to ensure reliability.

NERC's RSDP for 2017-2019 outlines a path for the ERO to fulfill its obligations to address standards-related regulatory directives. The ERO and industry developed the Enhanced Periodic Review Template[5] in 2015 with the intention of continuing to review the Reliability Standards for quality and content.

[5] Submitted to the NERC Board of Trustees for information in November 2014, along with the 2015-2017 RSDP.

Chapter 4 – Conclusion

NERC is continuing to work closely with industry stakeholders and FERC to resolve all outstanding directives. Completing the majority of this work has provided the opportunity for industry to strategically review the standards for content, including alignment with the risks to the Bulk-Power System; quality; and alignment with compliance expectations.

Appendix A – Regulatory Orders Containing Directives

Regulatory Orders by Year

NERC continues to collaborate with FERC on identifying the number of directives contained in each Commission Order. The table below lists each order, the date the order was issued, and the amount of the directives from the order that were addressed each year.

Table 2: Regulatory Orders Containing Standards-Related Directives

Order	Date Issued	Number of Directives	Directives Addressed (year/addressed)
Order on Compliance Filing (Issued 1/18/07) *Docket No. RR06-1-003*	01.18.2007	16	2007 - 14 2009 - 2
Preventing Undue Discrimination and Preference in Transmission Service *Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890*	02.16.2007	29	2008 - 28 2014 - 1
Mandatory Reliability Standards for the Bulk-Power System *Docket No. RM06-16-000; Order No. 693*	03.16.2007	344	2006 - 1 2007 - 4 2008 - 53 2009 - 19 2010 - 12 2011 - 63 2012 - 13 2013 - 49 2014 - 65 2015 – 39 2016 – 4 Not addressed - 22
Order on Violation Risk Factors (Issued 5/18/07) *Docket Nos. RR07-9-000, RR07-10-000*	05.18.2007	5	2007 - 5
Order on Compliance Filing Regarding NERC Rules of Procedure Order on Compliance Filing *Docket No. RR06-1-007*	06.07.2007	3	2007 - 2 2008 - 1
Order Approving Regional Reliability Standards for the Western Interconnection and Directing Modifications *Docket No. RR07-11-000*	06.08.2007	14	2007 - 2 2009 - 2
Order on Compliance Filing (Issued 11/16/07) Order on Compliance Filing pursuant to the Commission's May 2007 Order on Violation Risk Factors. *Docket Nos. RR07-9-003 and RR07-10-003*	11.16.2007	12	2007 - 12

Facilities Design, Connections and Maintenance Reliability Standards (Issued 12/27/07) Order on approving the Facilities Design, Connections and Maintenance Reliability Standards which are the planning and operating reliability standards. *Docket No. RM07-3-000; Order No. 705*	12.27.2007	12	2008 - 11 2013 - 1
Mandatory Reliability Standards for Critical Infrastructure Protection (Issued 1/18/08) Order approving the eight Critical Infrastructure Protection (CIP) Reliability Standards submitted by NERC on August 28, 2006. *Docket Nos. RM06-22-000; Order No. 706*	01.18.2008	103	2009 - 36 2011 - 4 2013 - 62 2015 - 1
Order 706-A - Order Denying Rehearing and Granting Clarification The Commission issues a final rule approving eight Critical Infrastructure Protection (CIP) Standards. *Docket No. RM06-22-001; Order No. 706-A*	05.16.2008	2	2011 - 2
Order on Violation Severity Levels Proposed by the Electric Reliability Organization The Commission approves the VSL assignments filed by NERC for the 83 Commission-approved Reliability Standards. The Commission also directs NERC to file modifications to VSLs relevant to five Reliability Standards. *Docket No. RR08-4-000*	06.19.2008	4	2008 - 3 2011 - 1
Order No. 713 - Modification of INT and TLR Standards; and ERO Interpretation of Requirements of Four Standards The Commission approves five of six modified Reliability Standards submitted by NERC that pertain to interchange scheduling and coordination. The Commission directs NERC to submit a filing that provides an explanation regarding one aspect of the TLR procedure. *Docket No. RM08-7-000; Order No. 713*	07.21.2008	3	2008 - 3
Order No. 716 - NUC Standard Commission approves the Nuclear Plant Interface Coordination Reliability Standard NERC submitted for approval on November 19, 2007 and supplemented on December 11, 2007. *Docket No. RM08-3-000; Order No. 716*	10.16.2008	9	2009 - 9
Order on Rehearing and Clarification and Accepting Compliance Filing in response to VSL Order	11.20.2008	2	2010 - 2

The Commission grants in part and denies in part rehearing and clarification of the VSL Order. The Commission accepts NERC's July 21, 2008 Compliance Filing revising certain VSLs submitted pursuant to the VSL Order. The Commission directs NERC to submit a further compliance filing that makes specific revisions. *Docket Nos. RR08-4-001 and RR08-4-002*			
Order on CIP VRFs Compliance Filing The Commission issued an Order approving 12 revised VRFs and approving 9 new VRFs. In addition, the Commission requires revisions to four of the new VRFs. *Docket Nos. RM06-22-002 and RM06-22-003*	01.27.2009	1	2009 – 1
Mandatory Reliability Standards for Critical Infrastructure Protection *Docket No. RM06-22-000; Order No. 706-B*	03.19.2009	1	2009 - 1
Modification of Interchange and TLR Reliability Standards ERO Interpretation of Specific Requirements of Four Reliability Standards *Docket Nos. RM08-7-000 and RM08-7-001; Order No. 713-A*	03.19.2009	2	2011 – 2
Version Two Facilities Design, Connections and Maintenance Reliability Standards *Docket No. RM08-11-000; Order No. 722*	03.20.2009	16	2009 - 11 2010 - 1 2011 - 4
Order No. 723 Approving WECC Regional Reliability Standard BAL-004-WECC-01 The Commission approved the regional Reliability Standard BAL-004-WECC-01 (Automatic Time Error Correction) and directed WECC to develop several modifications to the regional Reliability Standard. *Docket No. RM08-12-000; Order No. 723.*	05.21.2009	5	2009 - 2 2012 - 1 2013 - 2
ERO Interpretations of Specific Requirements of BAL-003-0 and VAR- 001-1 Reliability Standards The Commission approves the Interpretation of BAL-003-0 R2 and R5. The Commission remands to the ERO the proposed interpretation of VAR-001-1, Requirement R4 and directs the ERO to revise the interpretation. *Docket No. RM08-16-000*	05.21.2009	1	2014 – 1
Order Approving Version 2 of CIP Cyber Security Standards FERC approves the revised Version 2 CIP Reliability Standards to become effective on April 1, 2010. *Docket No. RD09-7-000*	09.30.2009	9	2009 – 9

Order 729 - Mandatory Reliability Standards for the Calc. of ATC, CBM, TRM, TTC and Existing Transmission Commitments for the BPS The Commission approves six Modeling, Data, and Analysis Reliability Standards submitted to the Commission for approval by the NERC. *Docket Nos. RM08-19-000, RM08-19-001, RM09-5-000, RM06-16-005*	11.24.2009	22	2010 - 1 2011 - 1 2013 - 7 2014 - 14
Order Addressing NERC's CIP Implementation Plan and Requiring Compliance Filing FERC issues an order addressing NERC's CIP Implementation Plan. *Docket No.RM06-22-010*	12.17.2009	5	2010 – 5
Order Approving TFE Procedures Amendment to NERC's ROP FERC approves NERC's petition to amend NERC's ROP, specifically by adding the Technical Feasibility Exceptions (TFE) to NERC CIP standards and direct NERC to submit a compliance filing. *Docket No. RR10-1-000*	01.21.2010	12	2010 - 10 2011 - 1 2012 - 1
Order 733 - PRC-023-1 The Commission issued a Final Order approving Reliability Standard PRC-023-1. *Docket No. RM08-13-000*	03.18.2010	31	2010 - 8 2011 - 19 2013 - 1 2014 - 3
Order Setting Deadline for Compliance Regarding BAL-003-0 The Commission directs NERC to submit a modification to BAL-003-0 that is responsive to the Commission's Directive in Order No. 693 within six months from the date of issuance of this order. *Docket No. RM06-16-010*	03.18.2010	1	2010 - 1
Order Addressing Compliance Filing and Approving Implementation Plan FERC accepts NERC's compliance filing and approves the Implementation Plan for nuclear power plant generator owners' and operators' compliance with Version 1 of the CIP Standards to become effective on the date of this order. *Docket No. RM06-22-011*	03.18.2010	2	2010 – 2
Order Addressing VSL Assignments to CIP Standards The Commission approves the proposed VSL assignments and establishes additional guidance for determining appropriate VSLs in the specific context of cyber security Requirements. *Docket No. RM06-22-008*	03.18.2010	5	2010 – 5

Order Directing NERC to Propose Modification of Electric Reliability Organization Rules of Procedure FERC directs NERC to submit a filing containing specific proposed modifications to the NERC Standards Development Process within 90 days of this Order and to fully comply with FERC's previous Directive to develop modifications to Reliability Standard FAC-008-1. *Docket No. RR09-6-000*	03.18.2010	2	2010 - 1 2011 - 1
Order Setting Deadline for Compliance Regarding TPL-002-0 FERC issues an Order setting a deadline of June 30, 2010 for NERC's compliance with Order 693 to modify Reliability Standard TPL-002-0. *Docket No. RM06-16-009*	03.18.2010	1	2011 – 1
Order Granting Rehearing for Further Consideration and Scheduling Technical Conference The Commission grants rehearing for the limited purpose of further consideration, and timely-filed requests for rehearing will not be deemed denied by operation of law and directs Commission staff to convene a technical conference. *Docket No. RM06-16-011*	05.13.2010	1	2010 – 1
Order on NERC Three-Year Performance Assessment FERC accepts the performance assessment of NERC as the ERO, and the Regional Entities, and finds that they continue to satisfy the statutory and regulatory criteria for certification. In addition, FERC directs NERC to submit informational filing addressing specific matters/concerns and take additional action as discussed in this order. *Docket Nos. RR09-7-000, AD10-14-000*	09.16.2010	2	2011 – 2
Order No. 742 - Final Rule on System Personnel Reliability Standards The Commission issues a final rule approving two Personnel Performance, Training and Qualifications (PER) Reliability Standards, PER-004-2 (Reliability Coordination–Staffing) and PER-005-1 (System Personnel Training). *Docket No. RM09-25-000; Order No. 742*	11.18.2010	4	2012 - 1 2014 - 3
Order No. 743 - Final Rule on Revision to the ERO Definition of Bulk Electric System FERC issues a final rule in which it adopts, with modifications, the proposal outlined in its March 18, 2010 Notice of Proposed Rulemaking to require the ERO to revise its definition of the term “bulk electric system." *Docket No. RM09-18-000; Order No. 743*	11.18.2010	5	2012 – 5

Letter Order Approving VSL for Version Two Facilities Design, Connection, and Maintenance Reliability Standards FERC issues an order approving the violation severity levels assigned to FAC-014-2 Requirements R1, R3, and R4 and orders a compliance filing to be made by January 6, 2010 with typographical corrections to violation severity levels for R2. *Docket Nos. RM08-11-002, RM08-11-003*	12.07.2010	1	2011 – 1
Order Approving Revisions to Two Reliability Standards and Directing a Compliance Filing FERC issues an Order Approving Revisions to Two Reliability Standards and Directing a Compliance Filing concerning INT-003-3 and BAL-006-2. *Docket No. RD10-04-000*	01.06.2011	1	2011 – 1
Order on VRFs and VLS for CIP Standards FERC issues an order in which it approves the proposed Version 2 and Version 3 VRFs and VSLs, subject to modifications discussed in the order. *Docket Nos. RD10-6-000 and RD09-7-002*	01.20.2011	9	2011 – 9
Order No. 749 - Final Rule Approving Three System Restoration Reliability Standards EOP-001-1, EOP-005-2, EOP-006-2, and Definition FERC issues an order approving EOP-001-1 (Emergency Operations Planning), EOP-005-2 (System Restoration from Blackstart Resources), and EOP-006-2 (System Restoration Coordination) as well as the definition of the term "Blackstart Resource" submitted to the Commission for approval. *Docket No. RM10-16-000*	03.17.2011	2	2014 - 1 2017 - 1
Order No. 747 - Final Rule Approving Planning Resource Adequacy Assessment Standard BAL-502-RFC-02 FERC approves regional Reliability Standard, BAL-502-RFC-02 (Planning Resource Adequacy Analysis, Assessment and Documentation), developed by RFC. The Commission also approves four regional reliability definitions related to the approved regional Reliability Standard and the violation risk factors and violation severity levels assigned to the BAL-502-RFC-02 Requirements. *Docket No. RM10-10-000; Order No. 747*	03.17.2011	2	Not addressed - 2
Order No. 748 - Final Rule Approving Interconnection Reliability Operating Limits Standards	03.17.2011	2	2015 – 2

The Commission issues a final rule approving NERC's proposed IRO-008-1, IRO-009-1, and IRO-010-1a and proposed revisions to Reliability Standards EOP-001-1, IRO-002-2, IRO-004-2, IRO-005-3, TOP- 003-1, TOP-005-2, and TOP-006-2, which remove requirements for the reliability coordinator to monitor and analyze system operating limits (SOL) other than IROLs. *Docket No. RM10-15-000; Order No. 748*			
Order No. 751 - Final Rule on Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive FERC issues a final rule in which it approves four revised regional Reliability Standards developed by the WECC and approved by NERC. These regional Reliability Standards have been designated by the Western Electricity Coordinating Council as FAC-501-WECC-1–Transmission Maintenance, PRC-004-WECC-1–Protection System and Remedial Action Scheme Misoperation, VAR-002-WECC-1–Automatic Voltage Regulators, and VAR-501-WECC-1–Power System Stabilizer. *Docket No. RM09-9-000; Order No. 751*	04.21.2011	7	2011 - 4 2013 - 2 Not addressed - 1
Order No. 752 - Final Rule on TOP-007-WECC-1 FERC issues a final rule in which it approves regional Reliability Standard TOP-007-WECC-1 (System Operating Limits) developed by WECC and submitted to the Commission for approval by NERC. The Commission also approves the retirement of WECC regional Reliability Standard TOP-STD-007-0, which is replaced by the regional Reliability Standard approved in this final rule. *Docket No. RM09-14-000; Order No. 752.*	04.21.2011	4	2011 - 4
Order No. 754 - Order Approving Interpretation of TPL-002-0 Requirement R1.3.10 FERC issues an order in which it approves an interpretation of Reliability Standard TPL-002-0 Requirement R1.3.10. *Docket No. RM10-6-000; Order No. 754*	09.15.2011	1	2012 - 1
Order Approving Reliability Standard FAC-008-3 FERC issues an order approving Reliability Standard FAC-008-3 (Facility Ratings), the associated VRFs and VSLs, and retirement of Reliability Standards FAC-008-1 (Facility Ratings Methodology) and FAC-009-1 (Establish and Communicate Facility Ratings). *Docket No. RD11-10-000*	11.17.2011	1	2012 - 1
Order Approving Reliability Standard FAC-013-2	11.17.2011	3	2012 - 3

FERC issues an Order Approving Reliability Standard FAC-013-2—Assessment of Transfer Capability for the Near-term Transmission Planning Horizon that NERC filed for approval on January 28, 2011. *Docket No. RD11-3-000*			
Order No. 758 - Order Approving Interpretation of Protection System Reliability Standard PRC-005-1 FERC issues a final rule in which it approves an interpretation to Requirement R1 of Commission-approved Reliability Standard PRC-005-1. FERC also directs NERC to develop modifications to the PRC-005-1 Reliability Standard through its Reliability Standards development process to address gaps in the Protection System maintenance and testing standard that were highlighted by the proposed interpretation. *Docket No. RM10-5-000; Order No. 758*	02.03.2012	2	2012 - 1 2014 - 1
Order No. 759 - Order Approving Transmission Relay Loadability Reliability Standard FERC issues a final rule in which it approves Reliability Standard PRC-023-2 (Transmission Relay Loadability) submitted by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. The Reliability Standard requires transmission owners, generation owners, and distribution providers to set load-responsive phase protective relays according to specific criteria to ensure that the relays reliably detect - and protect the electric network from - fault conditions, but do not limit reliability. *Docket No. RM11-16-000; Order No. 759*	03.15.2012	1	2013 - 1
Order No. 761 - Order Approving Version 4 Critical Infrastructure Protection Reliability Standards FERC issues a final rule in which it approves eight modified Critical Infrastructure Protection (CIP) Reliability Standards, CIP-002-4 through CIP-009-4, developed and submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. The CIP Reliability Standards provide a cybersecurity framework for the identification and protection of "Critical Cyber Assets" to support the reliable operation of the Bulk-Power System. *Docket No. RM11-11-000; Order No. 761*	04.19.2012	2	2012 - 1 2013 - 1
Order No. 762 - Transmission Planning Reliability Standards	04.19.2012	3	2012 - 1 2013 - 2

FERC issues a final rule in which it remands proposed Transmission Planning (TPL) Reliability Standard TPL-002-0b, submitted by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The proposed Reliability Standard includes a provision that allows for planned load shed in a single contingency provided that the plan is documented and alternatives are considered and vetted in an open and transparent process. *Docket No. RM11-18-000; Order No. 762*			
Order No. 763 - Order Approving Automatic Underfrequency Load Shedding and Load Shedding Plans Reliability Standards FERC issues a final rule in which it approves Reliability Standards PRC-006-1 (Automatic Underfrequency Load Shedding) and EOP-003-2 (Load Shedding Plans), developed and submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization certified by the Commission. *Docket No. RM11-20-000; Order No. 763*	05.07.2012	3	2012 - 2 2014 - 1
Order 772 - Order Approving PRC-006-SERC-1 FERC issues a final rule in which it approves regional Reliability Standard PRC-006-SERC-01 (Automatic Underfrequency Load Shedding Requirements), submitted to the Commission for approval by the North American Electric Reliability Corporation (NERC). Regional Reliability Standard PRC-006-SERC-01 is designed to ensure that automatic underfrequency load shedding protection schemes, designed by planning coordinators and implemented by applicable distribution providers and transmission owners in the SERC Reliability Corporation Region, are coordinated to mitigate the consequences of an underfrequency event effectively. *Docket. No. RM12-9-000; Order 772*	12.20.2012	2	2013 - 2
Order 773 - Order Approving Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure	12.20.2012	5	2013 - 4 2015 - 1

FERC issues a Final Rules approving modifications to the currently-effective definition of "bulk electric system" developed by the North American Electric Reliability Corporation (NERC), the Commission-certified Electric Reliability Organization. The Commission finds that the modified definition of "bulk electric system" removes language allowing for regional discretion in the currently-effective bulk electric system definition and establishes a bright-line threshold that includes all facilities operated at or above 100 kV. The modified definition also identifies specific categories of facilities and configurations as inclusions and exclusions to provide clarity in the definition of "bulk electric system." *Docket Nos. RM12-6-000 and RM12-7-000; Order No. 773*			
Order No. 777 Approving FAC-003-2 (Transmission Vegetation Management) FERC issues a final rule approving Reliability Standard FAC-003-2 (Transmission Vegetation Management), and three new definitions in the NERC Glossary of Terms – "Right-of-Way," "Vegetation Inspection," and "Minimum Vegetation Clearance Distance." FAC-003-2 also incorporates a new minimum annual inspection requirement, and incorporates new minimum vegetation clearance distances into the text of the standard. *Docket No. RM12-4-000; Order No. 777*	03.21.2013	5	2013 – 3 2015 – 1 Not addressed - 1
Order 779 - Final Rule on Reliability Standard for Geomagnetic Disturbances FERC issues Order No. 779, in which it directs NERC to submit to the Commission for approval proposed Reliability Standards that address the impact of GMD on the reliable operation of the Bulk-Power System. The Commission directs NERC to implement the directive in two stages. *Docket No. RM12-22-000; Order No. 779*	05.16.2013	17	2013 - 3 2015 - 14
Order 786 - Final Rule Approving Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) FERC issues a final rule approving NERC's proposed Transmission Planning Reliability Standard TPL-001-4. *Docket Nos. RM12-1-000 and RM13-9-000; Order No. 786*	10.17.2013	4	2014 - 1 Not addressed - 3
Order 789 - Approving Regional Reliability Standard BAL-002-WECC-2 - Contingency Reserve FERC issues a final rule approving regional Reliability Standard BAL-002-WECC-2 (Contingency Reserve). The final rule directs NERC to file an informational filing two years after implementation of the regional Reliability Standard. Docket *No. RM13-13-000; Order No. 789*	11.21.2013	1	Not addressed - 1

Order 791 - Approving Version 5 CIP Reliability Standards FERC issues a final rule approving the Version 5 Critical Infrastructure Protection (CIP) Reliability Standards, CIP-002-5 through CIP-011-1. The final rule also approves 19 new or revised definitions associated with the CIP Version 5 Reliability Standards for inclusion in the NERC Glossary of Terms. The final rule further directs NERC to develop modifications to the CIP Version 5 Reliability Standards, and submit informational filings. *Docket No. RM13-5-000; Order No. 791*	11.22.2013	13	2014 - 7 2015 - 6
Order 793 - Final Rule Approving Protection System Maintenance Reliability Standard FERC issues a final rule approving NERC's revised Reliability Standard, PRC-005-2 (Protection System Maintenance), which will supersede four existing Reliability Standards, PRC-005-1.1b (Transmission and Generation Protection System Maintenance and Testing), PRC-008-0 (Underfrequency Load Shedding Equipment Maintenance), PRC-011-0 (Undervoltage Load Shedding Equipment Maintenance), and PRC-017-0 (Special Protection System Maintenance and Testing). *Docket No. RM13-7-000; Order No. 793*	12.19.2013	2	2014 - 2
Order 794 - Approving Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting) FERC issues a final rule approving the Reliability Standard BAL-003-1 (Frequency Response and Frequency Bias Setting). *Docket No. RM13-11-000; Order No. 794*	01.16.2014	6	2014 - 2 Ongoing Requirement - 1 2015 – 1 Not addressed - 2
Order Directive Filing Standards FERC issues Order No. 795, in which it directs NERC to submit to the Commission for approval proposed Reliability Standards that requires certain registered entities take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System within 90 days of the date of the order. *Docket No. RD14-6-000; Order No. 795*	03.07.2014	1	2014 - 1
Generator Verification Reliability Standards FERC issues Order No. 796, in which it directs NERC to submit a violation severity level that addresses a transmission planner's obligation to provide a technical description of why a model submitted by a generation owner is not usable for Requirement R6 of MOD-026-1 and Requirement R5 of MOD-027-1. *Docket No. RM13-16-000; Order No. 796*	03.20.2014	1	2014 - 1

Physical Security Reliability Standard FERC issues Order No. 802, in which it directs NERC to submit updates to CIP-014-1 (Physical Security). *Docket No. RM14-15-000; Order No. 802*	11.20.2014	2	2015 – 1 Not addressed - 1
Order 803 - Approving Reliability Standard PRC-005-3 (Protection System and Automatic Reclosing Maintenance) FERC issues a final rule approving the Reliability Standard PRC-005-3 (Protection System and Automatic Reclosing Maintenance). *Docket No. RM14-8-000; Order No. 803*	1.22.2015	2	2015 – 1 Not addressed - 1
Order No. 804 Approving Reliability Standard MOD-031-1 FERC issues an order approving Reliability Standard MOD-031-1 (Demand and Energy Data) as well as proposed definitions for the terms Demand Side Management and Total Internal Demand. *Docket No. RM14-12-000; Order No. 804*	2.19.2015	2	2015 - 2
Order on the RBR Initiative NERC ROP Revisions and Requiring Compliance Filing Errata Notice to the Order on the RBR Initiative NERC ROP Revisions and Requiring Compliance Filing. FERC issues an order approving and denying in part the Risk-Based Registration (RBR) initiative NERC Rules of Procedure (ROP) revisions submitted on December 11, 2014. FERC directs NERC to: (1) provide, within 60 days, more information on the proposal to remove Load-Serving Entities from the registry criteria to ensure there are no reliability gaps; (2) revise, within 60 days, ROP Appendix 5B to include Reliability Standard PRC-005 as applicable to UFLS-Only Distribution Providers; (3) modify, within 60 days, Appendix 5A Section III.D; (4) submit a one-year informational filing discussing the implementation of the RBR program; and (5) provide the Commission with notice of review panel discussions. *Docket No. RR15-4-000*	3.19.2015	5	2015 – 3 2017 - 2
Order No. 808 Approving Reliability Standards COM-001-2 and COM-002-4 FERC issues an order approving Reliability Standards COM-001-2 (Communications) and COM-002-4 (Operating Personnel Communications Protocols). *Docket No. RM14-13-000; Order No. 808*	4.16.2015	1	2016- 1
Order No. 810 Approving Reliability Standard BAL-001-2	4.16.2015	2	2016-1 Not addressed - 1

FERC issues an order approving Reliability Standard BAL-001-2 (Real Power Balancing Control Performance). *Docket No. RM14-10-000; Order No. 810*			
Order Approving Reliability Standard PRC-004-3 FERC issues an order approving Reliability Standard PRC-004-3 (Protection System Misoperation Identification and Correction), including approval of two new defined terms to include in the NERC Glossary of Terms as well as the implementation plan and associated VRFs and VSLs. FERC also directs NERC to submit a compliance filing, within 60 days of the order, to address certain concerns regarding the VRF designations for Requirement R1 through R6. *Docket No. RM14-14-000*	5.13.2015	1	2015 - 1
Order on the Amended CCC Charter FERC issues an order conditionally approving NERC's proposed revisions to the Compliance and Certification Committee (CCC) Charter and directs NERC to submit a compliance filing within 60 days of the date of this order. *Docket No. RM15-11-000*	8.21.2015	1	Not addressed - 1
Order Approving RBR Initiative ROP Revisions Compliance Filing FERC issues an order accepting the July 17, 2015 Risked-Based Registration (RBR) initiative-related compliance filing that proposed to: eliminate the Load-Serving Entity (LSE) function from the registry criteria and to revise the NERC Rules of Procedure (ROP). FERC also directs NERC to submit an informational filing on the actual effects of this LSE change after it is implemented. *Docket No.RR15-04-001*	10.15.2015	1	2017– 1
Order Conditionally Approving Revised *Pro Forma* and Eight Revised RDAs Errata Notice FERC issues an order conditionally approving NERC's petition to approve the *Pro Forma* Regional Delegation Agreement (RDA) and eight RDAs effective January 1, 2016, but directs NERC to modify the agreements and submit a compliance filing within 120 days of the date of this order. *Docket No. RR-15-12-001*	11.02.15	5	2015 – 5
Order on 2016 Business Plans and Budgets Errata Notice FERC issues an order accepting the 2016 business plans and budgets of NERC, the Regional Entities, and Western Interconnection Regional Advisory Board (WIRAB). *Docket No. RR15-16-001*	11.2.15	1	2016-1

Order No. 817 Approving TOP and IRO Reliability Standards FERC issues a final rule approving revisions to the Transmission Operations and Interconnection Reliability Operations and Coordination Reliability Standards. The final rule directs NERC to make three modification to the standards within 18 months of the effective date of the final rule. *Docket No.RM-15-16-000*	11.19.15	5	Not Addressed – 1
Order No. 822 Adopting Improvements to CIP Standards FERC issues a final rule adopting revisions to seven Critical Infrastructure Protection (CIP) Reliability Standards, and also directs NERC to develop modifications and conduct a study. *Docket No.RM-15-14-000*	1.22.16	4	Not Addressed – 4
Order No. 824 Approving Availability of Certain NERC Databases to the Commission FERC issues a final rule approving availability of certain NERC databases to the Commission.	6.16.16	1	Not Addressed-1
Order No. 829 Directing Standard for Supply Chain Cyber Controls FERC issues a final rule requiring the development of a new Reliability Standard on supply chain risk management for industrial control system hardware, software, and computing and networking services associated with bulk electric system operations.	7.21.16	1	Not Addressed - 1
Order No. 830 on GMD Reliability Standard FERC issues a final rule approving the Second Stage Geomagnetic Disturbances (GMD) Reliability Standard and directs NERC to develop three modifications.	9.22.16	6	Not Addressed - 6
Order Approving Reliability Standards IRO-018-1 and TOP-010-1 FERC issues an order approving Reliability Standards IRO-018-1 (Reliability Coordinator Real-time Reliability Monitoring and Analysis Capabilities) and TOP-010-1 (Real-time Reliability Monitoring and Analysis Capabilities).	9.22.16	1	Addressed-1
Order No. 835 Approving Reliability Standard BAL-002-2 FERC issues a final rule approving Reliability Standard BAL-002-2 (*Disturbance Control - Contingency Reserve for Recovery from a Balancing Contingency Event*), eight new or revised definitions to be included in the NERC Glossary, retirement of currently-effective Reliability Standard BAL-002-1, associated violation risk factors and violation severity levels, and implementation plan	1.19.17	4	Not Addressed – 4

Appendix B –Directives Listed by Commission Order

Directives by Commission Order (Publication Date)

Below is a list of all of the directives issued by Commission. The table includes a summary of the directive, information on the order in which it was issued and the status of resolving the directive (i.e., the estimated or actual date for a filing with FERC addressing the directive).

Table 3: Directives by Commission Order

Directive Summary	Document Name	Publication Date	Order No.	FERC ORDER / DOCKET	Paragraph Reference	Actual NERC Filing to FERC Date
S- Ref 10001 - Further, we adopt the NOPR proposal to require the ERO to submit a modification to the glossary that updates the definition of "operating reserves," as required in our discussion of BAL-002-0 and BAL-005-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1896	1/29/2016
S- Ref 10002 - ...directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Bulk-Power System.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1894	5/10/2013
S- Ref 10003 - ...directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Reliable Operation.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1894	5/10/2013
S- Ref 10004 - ...directs the ERO to modify the glossary through the Reliability Standards development process to include the statutory definitions of the terms Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1894	5/10/2013
S- Ref 10005 - ...directs the ERO to submit a modification to the glossary that enhances the definition of "generator operator" to reflect concerns of the commenters and the direction ["to include aspects unique to ISOs, RTOs and pooled resource organizations"] provided by the Commission in other sections of FERC Order 693.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1895 (See also Para 1887 and Para 130-145)	2013 N/A - Withdrawn by FERC Order No. 788

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10006 - ...directs the ERO to submit a modification to the glossary that enhances the definition of "transmission operator" to reflect concerns of the commenters and the direction ["to include aspects unique to ISOs, RTOs and pooled resource organizations"] provided by the Commission in other sections of FERC Order 693.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1895 (See also Para 1887 and Para 130-145)	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10008 - ... direct the ERO to file a modification of the ERCOT regional difference to include the requirements concerning frequency response contained in section 5 of the ERCOT protocols.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 315	9/18/2013
S- Ref 10009 - …develop a modification to the Reliability Standard that refers to the ERO rather than to the NERC Operating Committee in Requirements R4.2 and R6.2.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 321	9/9/2010
S- Ref 10010 - ...direct the ERO to modify this Reliability Standard to substitute Regional Entity for regional reliability organization as the compliance monitor.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 321	9/9/2010
S- Ref 10011 - …direct the ERO to submit a modification to BAL-002-0 that includes a Requirement that explicitly provides that DSM may be used as a resource for contingency reserves, subject to the clarifications provided below.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 330	1/29/16
S- Ref 10012 - ...direct the ERO to submit a modification to BAL-002-0 to include a continent-wide contingency reserve policy.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 340	1/29/16
S- Ref 10013 - ... direct the ERO to address the concerns expressed by the Commission about having enough contingency reserves to respond to an event on the system in Requirement R3.1 and how such reserves are measured.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 351	1/29/16

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10014 - ... direct the ERO to develop a modification to the Reliability Standard requiring that any single reportable disturbance that has a recovery time of 15 minutes or longer be reported as a violation of the Disturbance Control Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 354	1/29/16
S- Ref 10015 - ...direct the ERO, through the Reliability Standards development process, to modify this Reliability Standard to define a significant deviation and a reportable event, taking into account all events that have an impact on frequency, e.g., loss of supply, loss of load and significant scheduling problems, which can cause frequency disturbances and to address how balancing authorities should respond.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 355	5/9/2014
S- Ref 10016 - …direct the ERO to determine the appropriate periodicity of frequency response surveys necessary to ensure requirement R2 and other requirements are being met; also modify measure M1 based on this determination.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 369	3/29/2013
S- Ref 10017 - ... direct the ERO to either modify this Reliability Standard or develop a new Reliability Standard that defines the necessary amount of frequency response needed for Reliable Operation and methods of obtaining and measuring that frequency response is available.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 372	3/29/2013
S- Ref 10018 - The Commission agrees with the shortcomings identified by NERC regarding WECC-BAL-STD-002-0 and expects WECC in developing a permanent, replacement standard to address these shortcomings as it has committed to do.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 54	3/25/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10019 - Further, it is important that regional Reliability Standards and NERC Reliability Standards achieve a reasonable level of consistency in the structure of a Reliability Standard so that there is a common understanding of the element.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 55	3/25/2009
S- Ref 10020 - WECC will provide an opportunity to address these concerns when developing a permanent, replacement standard. The Commission agrees that this is a reasonable approach and will expect WECCs submission of a replacement standard to adequately address these stakeholder concerns. (Xcel and California Cogeneration contend that the Commission should remand WECC-BAL-STD-002-0 because of ambiguities in the terms load responsibility and firm transaction.)	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 56	3/25/2009
S- Ref 10021 - …direct the ERO to modify BAL-003 to include Levels of Non-Compliance.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 375	3/8/2008
S- Ref 10022 - ... directs the ERO to develop a modification to BAL-004-0 through the Reliability Standards development process that includes Levels of Non-Compliance and additional Measures for Requirement R3.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 382	12/1/2010
S- Ref 10023 - In the five-year review cycle of the standard, perform research that would provide a technical basis for the present or any alternative approach that is more effective and helps reduce inadvertent interchange.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 385	
S- Ref 10024 - ...directs WECC to develop revisions to the provision so that a balancing authority will know with specificity the circumstances that trigger the actions required by Requirement R1.2.	Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction	5/21/2009	Order 723	RM08-12-000	Para 30	8/20/2013 Regional

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10025 - ...directs WECC to develop a modification to the regional Reliability Standard consistent with CCs and NERCs explanation that the limit set forth in Requirement 2 of 24 hours per calendar quarter is an accumulated total for the period…	Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction	5/21/2009	Order 723	RM08-12-000	Para 34	8/20/2013 Regional
S- Ref 10026 - ...direct NERC to develop in its Rules of Procedure, a methodology for organizing and managing regional definitions and terminology consistent with the principles discussed above.	Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction	5/21/2009	Order 723	RM08-12-000	Para 39	Complete - Regional Definitions included in NERC Glossary
S- Ref 10027 - ...direct that the violation risk factors assigned to BAL-004-WECC-01, Requirements R1, R2, R3, and R4 be modified from lower to medium.	Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction	5/21/2009	Order 723	RM08-12-000	Para 51	8/28/2009
S- Ref 10028 - ...directs the ERO and WECC to submit violation severity levels for each Requirement and sub-Requirement that has been assigned a violation risk factor.	Western Electricity Coordinating Council Regional Reliability Standard Regarding Automatic Time Error Correction	5/21/2009	Order 723	RM08-12-000	Para 54	10/23/2009
S- Ref 10029 - ... direct the ERO to modify BAL-005-0 through the Reliability Standards development process to develop a process to calculate the minimum regulating reserve for a balancing authority, taking into account expected load and generation variation and transactions being ramped into or out of the balancing authority.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 396	4/20/2016

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10030 - ... clarifies that its direction to the ERO in this section is for it to develop a modification to BAL-005-0 through the Reliability Standards development process that changes the title of the Reliability Standard to be neutral as to the source of regulating reserves and allows the inclusion of technically qualified DSM and direct control load management as regulating reserves, subject to the clarifications provided in this section.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 404	4/20/2016
S- Ref 10031 - ...the comments of Xcel and FirstEnergy should be addressed by the ERO when this Reliability Standard is revisited as part of the ERO's Work Plan.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 415	4/20/2016
S- Ref 10032 - ...direct NERC to submit, within six months from the date of issuance of this order, a modification to BAL-003-0 that complies with the Commissions directives as set forth in Order No. 693.	Order Setting Deadline for Compliance - Docket No. RM06-16-010	3/18/2010	130 FERC ¶ 61,218	RM06-16-010	Para 14	5/25/2010
S- Ref 10033 - Given that most of the commenters concerns over the inclusion of DSM as part of regulating reserves relate to the technical requirements, the Commission clarifies that to qualify as regulating reserves, these resources must be technically capable of providing the service. In particular, all resources providing regulation must be capable of automatically responding to real-time changes in load on an equivalent basis to the response of generation equipped with automatic generation control.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 406	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10034 - The Commission adopts the NOPR proposal to require the ERO to modify the Reliability Standards to include a Measure that provides for a verification process over the minimum required automatic generation control or regulating reserves a balancing authority maintains.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 418	Credit take in 2014

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10035 - ...direct to consider those (FirstEnergy) suggestions in its Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 419	4/20/2016
S- Ref 10036 - ...direct the ERO to develop a modification to BAL-006-1 that adds Measures concerning the accumulation of large inadvertent imbalances and Levels of Non-Compliance.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 428	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10037 - Examine the WECC time error correction procedure as a possible guide. The Commission asks the ERO, when filing the new Reliability Standard, to explain how the new Reliability Standard satisfies the Commission's concerns.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 438	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10038 - ...direct the ERO to modify the regional differences so that they reference the current Reliability Standards and are in the standard form, which includes Requirements, Measures and Levels of Non-Compliance. The ERO should explore FirstEnergy's request to define the function of a waiver in its Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 444	4/20/2016
S- Ref 10039 - …direct the ERO, as part of its Work Plan, to consider in the Reliability Standards development process, possible revisions to CIP-001-1 that address our concerns regarding the need for wider application of the Reliability Standard. Further, when addressing such applicability issues, the ERO should consider whether separate, less burdensome requirements for smaller entities may be appropriate to address these concerns.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 460	12/31/2012
S- Ref 10040 - Define sabotage and provide guidance on triggering events that would cause an entity to report an event.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 461	12/31/2012

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10041 - Consider FirstEnergy's suggestions to differentiate between cyber and physical security sabotage and develop a threshold of materiality.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 462	12/31/2012
S- Ref 10042 - ...direct the ERO to incorporate a periodic review or updating of the sabotage reporting procedures and for the periodic testing of the sabotage reporting procedures.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 466	12/31/2012
S- Ref 10043 - ...direct the ERO to address our underlying concern regarding mandatory reporting of a sabotage event.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 468	12/31/2012
S- Ref 10044 - …direct the ERO to explore ways to address these concerns – including central coordination of sabotage reports and a uniform reporting format – in developing modifications to the Reliability Standard with the appropriate governmental agencies that have levied the reporting requirements.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 469	12/31/2012
S- Ref 10045 - ...direct the ERO to provide advice to entities that have concerns about the reporting of particular circumstances as they arise.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 461	12/31/2012
S- Ref 10046 - Modify CIP-001-1 to require an applicable entity to contact appropriate governmental authorities in the event of sabotage within a specific period of time, even if it is a preliminary report.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 470	12/31/2012
S- Ref 10047 - Therefore, we adopt our proposal to require the ERO to modify COM-001-1 to apply to generator operators and distribution providers.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 493 Sen 4	5/14/2014
S- Ref 10048 - Address TAPS, Entergy, Six Cities, and FirstEnergy concerns through the standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 491	5/14/2014

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10049 - Specify requirements for using telecommunication facilities during normal and emergency conditions that reflect the roles of the applicable entities and their impact of reliable operation, and include adequate flexibility.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 503	5/14/2014
S- Ref 10050 - Address TAPS, Entergy, Six Cities, and FirstEnergy concerns through the standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 503 and 504	5/14/2014
S- Ref 10051 - Although we direct that the regional reliability organization should not be the compliance monitor for NERCNet, we leave it to the ERO to determine whether it is the appropriate compliance monitor or if compliance should be monitored by the Regional Entities for NERCNet User Organizations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 507	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10052 - …adopt our proposal to require the ERO to modify COM-002-2 to apply to distribution providers through its Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 512	5/14/2014
S- Ref 10053 - Address APPAs concern through the standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 515	5/14/2014
S- Ref 10054 - Include a requirement for the reliability coordinator to assess and approve only those actions that have impacts beyond the area views of the transmission operators and balancing authorities.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 520	3/18/2015 First: 4/16/2013
S- Ref 10055 - Consider Xcels suggestion that the entity taking operating actions should not be held responsible for the delays caused by the reliability coordinators assessment and approval.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 523	5/14/2014
S- Ref 10056 - Establish tightened communication protocols, especially for communications during alerts and emergencies. Establish uniformity to the extent practical on a continent-wide basis.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 531	5/14/2014

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10057 - Address Santa Clara, FirstEnergy, and Six Cities concerns in the reliability standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 539	5/14/2014
S- Ref 10058 - Regarding APPAs suggestion that it may be beneficial to include communication protocols in the relevant Reliability Standard that governs those types of emergencies, we direct that it be addressed in the Reliability Standards Development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 533	5/14/2014
S- Ref 10059 - Accordingly, the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 548	12/31/2009
S- Ref 10060 - In addition, the ERO should consider SoCal Edison's suggestion in the ERO's Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 548	12/31/2009
S- Ref 10062 - ... direct the ERO to develop a modification through the Reliability Standards development process clarifying that when the load reduction plan of Requirement R2 involves load shedding, such load shedding be capable of being implemented as soon as possible when required to mitigate an IROL violation but in no case in more than 30 minutes.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 555	12/31/2009
S- Ref 10063 - ...direct the ERO to determine the optimum number of continent-wide system states and their attributes and to modify the Reliability Standards through the Reliability Standards development process to accomplish this objective.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 561	12/29/2014
S- Ref 10064 - ...direct the ERO to consider such a pilot program as it modifies EOP-001-0 through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 562	12/29/2014

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10065 - Clarifies that the actual emergency plan elements, and not the for consideration elements of Attachment 1, should be the basis for compliance.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 565	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10066 - Address emergencies resulting not only from insufficient generation but also insufficient transmission capability, particularly as it affects the implement of the capacity and energy emergency plan.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 571	12/29/2014
S- Ref 10067 - ...directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 573	12/29/2014
S- Ref 10068 - ...direction that the ERO modify the Reliability Standard to ensure that the TLR procedure is not used to mitigate actual IROL violations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 577	9/9/2010
S- Ref 10069 - The issues raised by ISO-NE should be addressed through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 582	9/9/2010
S- Ref 10070 - ...directs that the ERO considers adding Measures and Levels of Non-compliance in the Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 582	9/9/2010
S- Ref 10072 - ...directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 595	12/29/2014

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10073 - The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel. P 603: the Commission directs the ERO to develop a modification to EOP-003-1 through the Reliability Standards development process that: (1) includes a requirement to develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on an overarching criteria that take into account system characteristics and (2) requires periodic drills of simulated load shedding.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 597; Para 603	12/29/2014
S- Ref 10074 - Consider comments from APPA in the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 601	12/29/2014
S- Ref 10075 - ...direct the ERO to change its Rules of Procedure to assure that the Commission also receives these reports within the same time frames as DOE.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 618	5/7/2012
S- Ref 10076 - Consider APPAs concern about generator operators and LSEs analyzing performance of their equipment and provide data and information on the equipment to assist others with analysis.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 612	12/31/2012
S- Ref 10077 - ...direct the ERO to consider all comments (Xcel) in future modifications of the Reliability Standard through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 615	12/31/2012
S- Ref 10078 - The ERO should consider this issue (APPA) through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 616	12/31/2012

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S- Ref 10079 - ...direct the ERO to develop a modification to EOP-004-1 through the Reliability Standards development process that includes any Requirements necessary for users, owners and operators of the Bulk-Power System to provide data that will assist NERC in the investigation of a blackout or disturbance.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 617	12/31/2012
S- Ref 10080 - …direct the ERO to develop a modification to EOP-005-1 through the Reliability Standards development process that identifies time frames for training and review of restoration plan requirements to simulate contingencies and prepare operators for anticipated and unforeseen events and gathers the data from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 630	12/31/2009
S- Ref 10081 - ...direct the ERO to gather data, pursuant to § 39.5(f) of the Commission's regulations, from simulations and drills of system restoration on the time it takes to restore power to the auxiliary power systems of nuclear power plants under its data gathering authority and report that information to the Commission on a quarterly basis.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 629	12/31/2009 4/30/2009 6/1/2009 8/31/2009 11/30/2009
S- Ref 10082 - Consider commenters concerns in future modifications of the reliability standard, including those that refer to Attachment 1.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 628	12/31/2009
S- Ref 10083 - ...direct the ERO to consider the issues raised by NRC in future revisions of the Reliability Standard through the Reliability Standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 629	12/31/2009

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S- Ref 10084 - ... direct the ERO to develop a modification to EOP-006-1 through the Reliability Standards development process that ensures that the reliability coordinator, which is the highest level of authority responsible for reliability of the Bulk-Power System, is involved in the development and approval of system restoration plans.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 638	12/31/2009
S- Ref 10085 - ...direct the ERO to consider these suggestions in future revisions to improve EOP-007-0, through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 647	12/31/2009
S- Ref 10086 - With regard to TANCs request for regional flexibility in determining the appropriate mix of facilities needed to achieve the reliability objectives, it is our understanding that the Reliability Standard provides for the number and location of blackstart units to vary depending on the specific requirements of each system. We believe that uniformity will be required, however, in the criteria used to determine the number and location of blackstart units and testing requirements.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 646	12/31/2009
S- Ref 10087 - ... centrally dispatched generation control centers, must provide for the minimum backup capabilities discussed above but may do so through other means, such as contracting for these services instead of through dedicated backup control centers.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 670	2/11/2011
S- Ref 10088 - Provide for backup capabilities that, at a minimum, must be capable of operating for a prolonged period of time, generally defined by the time it takes to restore the primary control center.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 663	2/11/2011
S- Ref 10089 - Provide for backup capabilities that, at a minimum, must include a requirement that all reliability coordinators have full backup control centers.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 670	2/11/2011

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S- Ref 10090 - Provide for backup capabilities that, at a minimum, must provide for a minimum functionality to replicate the critical reliability functions of the primary control center.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 663	2/11/2011
S- Ref 10091 - Provide for backup capabilities that, at a minimum, must provide that the extent of the backup capability be consistent with the impact of the loss of the entity's primary control center on the reliability of the bulk power system.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 672	2/11/2011
S- Ref 10092 - Provide for backup capabilities that, at a minimum, must require transmission operators and balancing authorities that have operational control over significant portions of generation and load to have minimum backup capabilities.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 663	2/11/2011
S- Ref 10093 - Provide for backup capabilities that, at a minimum, must be independent of the primary control center.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 663	2/11/2011
S- Ref 10094 - Consider suggestions for improvements in future revisions of the standards.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 676	12/31/2009
S- Ref 10095 - Consider FirstEnergy's suggestion to include a reference to TPL-004-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 692	8/22/2014
S- Ref 10096 - ... direct the ERO to develop a modification to FAC-002-0 through the Reliability Standards development process that amends Requirement R1.4 to require evaluation of system performance under both normal and contingency conditions by referencing TPL-001 through TPL-003.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 693	9/9/2010
S- Ref 10097 - Address other commenters concerns in future revisions to the standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 687	8/22/2014

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S- Ref 10098 - Address the issue of bright-line applicability of 200 kV and above through the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 706	12/21/2011
S- Ref 10099 - Incorporate suggestions to include facilities at lower voltages that are associated with IROLs.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 706	12/21/2011
S- Ref 10100 - ... Direct the ERO to develop a Reliability Standard that defines the minimum clearance needed to avoid sustained vegetation-related outages that would apply to transmission lines crossing both federal land and non-federal land.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 732	12/21/2011
S- Ref 10101 - Collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results to develop a standard that would apply to both federal and non-federal lands. NERC should gather and analyze the necessary data regarding vegetation management issues on public lands. If NERC's analysis indicates that there are issues that should be addressed, NERC should propose a means to address the concern, for example by issuing an alert, or propose other appropriate action."	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007; 3/21/2013	Order 693; 777	RM06-16-000; RM12-4-000	Order 693 Para 732; Order 777 Para 129, 130	Not standards' related (TADS/RAPA)
S- Ref 10102 - ... direct the ERO to develop an acceptable definition that covers facilities that impact reliability but balances extending the applicability of this standard against unreasonably increasing the burden on transmission owners.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 708	12/21/2011

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S- Ref 10103 - FirstEnergy and Xcel suggest that if the applicability of this Reliability Standard is expanded, the Commission should allow flexibility in complying with this Reliability Standard for lower-voltage facilities, or allow lower-voltage facilities, or allow lower-voltage facilities one year before the Reliability Standard is implemented. The ERO should consider these comments when determining when it would request that the modification of this Reliability Standard to go into effect.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 709	12/21/2011
S- Ref 10104 - ...direct the ERO to develop compliance audit procedures, using relevant industry experts, which would identify appropriate inspection cycles based on local factors.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 721	12/21/2011
S- Ref 10105 - FirstEnergy suggests that rights-of-way be defined to encompass the required clearance areas instead of the corresponding legal rights, and that the standards should not require clearing the entire right-of-way when the required clearance for an existing line does not take up the entire right-of-way....directs the ERO to address this suggestion in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 734	12/21/2011
S- Ref 10106 - Consider EEIs suggestion for having this information available for review upon request of a registered user, owner, and operator as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 739	6/15/2011
S- Ref 10107 - ...direct the ERO to submit a modification to FAC-008-1 that requires transmission and generation facility owners to document underlying assumptions and methods used to determine normal and emergency facility ratings.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 739	6/15/2011

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S- Ref 10108 - Ensure that the methodology chosen is consistent with standards developed in an open process like IEEE or CIGRE. The ERO should consider the concerns raised by LPPC and MRO in its Reliability Standards development process, and is hereby directed to do so. The Commission does not expect there to be any regional differences because the only differences should be from different underlying assumptions that are not defined by the Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 742	6/15/2011
S- Ref 10109 - The Commission's proposed modification would require identifying and documenting the limiting component for all facilities and the increase in rating if that component were no longer the most limiting component; in other words, the rating based on the second-most limiting component.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 756	6/15/2011
S- Ref 10110 - Consider International Transmissions comments regarding applying this directive only for lines where the conductor itself is not the limiting element as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 760	6/15/2011
S- Ref 10111 - Consider comments from FirstEnergy and MISO that generators will have difficulty determining the increase in ratings due to the next limiting element through the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 760	6/15/2011
S- Ref 10112 - Consider Xcels comments that an actual test be used by generator operators to determine capabilities as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 765	6/15/2011
S- Ref 10113 - Consider FirstEnergy's comments that compliance with NRC rating methodologies should be assumed to comply with NERC reliability standards as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 765	6/15/2011

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S- Ref 10114 - Consider the comments by the Valley Group regarding dynamic line ratings as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 768	6/15/2011
S- Ref 10115 - Add or update the compliance measures in the standard as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 770	6/15/2011
S- Ref 10116 - Although we are not proposing to approve or remand this Reliability Standard, because it is applicable to the regional reliability organization, the Commission agrees with APPA, International Transmission and MidAmerican that, at a minimum, this Reliability Standard should provide a framework for the transfer capability calculation methodology, including data inputs and modeling assumptions.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 779	11/21/2008
S- Ref 10117 - The Commission agrees with APPA that there should be an umbrella organization to assure consistency within the Eastern Interconnection and the other interconnections. We believe that the best organization to do this would be the ERO, because it is the only organization with knowledge of all of the individual Regional Entities that can carry out this function. Therefore, we direct the ERO to modify this Reliability Standard to provide such a framework.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 779	11/21/2008
S- Ref 10118 - Process used to determine transfer capabilities should be transparent to the stakeholders. The results of those calculations should be available to qualified entities on a confidential basis.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 782	11/21/2008
S- Ref 10119 - The process and criteria used to determine transfer capabilities for use in calculating ATC must be identical to those used in planning and operating the system.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 782	11/21/2008

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S- Ref 10122 - ...direct the ERO, within 90 days of our subsequent order on proposed modifications to the ERO's rules, to comply with the Commissions directive in Order No. 693 to modify Reliability Standard FAC-008-1.	Order Directing NERC to Propose Modification of ERO RoPs - Docket No. RR09-6-000	3/18/2010	130 FERC ¶ 61,203	RR09-6-000	Para 29	6/15/2011
S- Ref 10123 - ...direct the ERO to propose a modification to its Rules of Procedure and the Standards Development Process to ensure that the ERO can comply with a Commission directive to develop a new or modified Reliability Standard pursuant	Order Directing NERC to Propose Modification of ERO RoPs - Docket No. RR09-6	3/18/2010	130 FERC ¶ 61,203	RR09-6-000	Para 26	12/23/2010
S- Ref 10124 - Make the standard applicable to reliability coordinators.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 790	11/21/2008
S- Ref 10128 - ...directs the ERO to develop modifications to FAC-012-1 and FAC-013-1 to comply with the relevant directives of Order No. 693 to include, but not limited to, removing redundant provisions for the calculation of transfer capability addressed elsewhere in the MOD Reliability Standards.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 291	1/28/2011

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S- Ref 10129 - ...direct the ERO, through the Reliability Standards development process, to modify FAC-012-1 and any other appropriate Reliability Standards to assure consistency in the determination of TTC/TFC for services provided under the pro forma OATT, and requires that those processes be the same as those used in operation and planning for native load and reliability assessment studies.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1051	11/21/2008
S- Ref 10130 - ...direct the ERO, through the Reliability Standards development process, to modify FAC-012-1 and any other appropriate Reliability Standards to...and requires that those processes be the same as those used in operation and planning for native load and reliability assessment studies.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1051	11/21/2008
S- Ref 10131 - …direct the ERO to submit a filing within 90 days of the date of this order either withdrawing this regional difference or providing additional information.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 825	3/26/2007
S- Ref 10132 - Include a requirement that interchange information must be submitted for all point-to-point transfers entirely within a balancing authority area, including all grandfathered and non-Order No. 888 transfers.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 817	2/27/2014
S- Ref 10133 - …direct the ERO to consider Santa Clara's comments, and whether some more explicit language would be useful, in the course of modifying INT-001-2 through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 819	2/27/2014
S- Ref 10134 - ...direct the ERO to consider adding these Measures and Levels of Non-Compliance to the Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 843	2013 N/A - Withdrawn by FERC Order No. 788

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S- Ref 10135 - ...direct the ERO to consider adding these Measures and Levels of Non-Compliance to the Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 848	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10136 - ...direct the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that makes it applicable to reliability coordinators and transmission operators.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 866	3/18/2015 First: 4/16/2013
S- Ref 10137 - ...direct the ERO to develop a modification to INT-006-1 through the Reliability Standards development process that requires reliability coordinators and transmission operators to review energy interchange transactions from the wide-area and local area reliability viewpoints respectively and, where their review indicates a potential detrimental reliability impact, communicate to the sink balancing authorities necessary transaction modifications before implementation.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 866	3/18/2015 First: 4/16/2013
S- Ref 10138 - …direct that the ERO consider the suggestions made by EEI and TVA and address the questions raised by Entergy and Northern Indiana in the course of the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 866	2/27/2014
S- Ref 10139 - Consider APPAs suggestion to clarify what reliability entity the standard applies as part of the standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 872	2/27/2014
S- Ref 10140 - Consider APPAs suggestion to clarify what reliability entity the standard applies as part of the standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 875	2/27/2014
S- Ref 10141 - Consider Northern Indiana's and ISO-NEs suggestions in the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 887	2/27/2014

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S- Ref 10142 - ...direct the ERO to develop modifications to the Reliability Standard through the Reliability Standards development process that reflect the process set forth in the NERC Rules of Procedures and eliminate the regional reliability organization as an applicable entity.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 896	3/18/2015 First: 4/16/2013
S- Ref 10143 - ...direct the ERO to consider adding Measures and Levels of Non-Compliance in the Reliability Standard as requested by APPA.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 897	3/18/2015 First: 4/16/2013
S- Ref 10144 - While APPA, FirstEnergy and California Cogeneration suggest possible changes to IRO-001-1, they do not suggest that the proposed Reliability Standard should not be approved. The ERO should consider the commenters' suggestions when modifying the Reliability Standard pursuant to its Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 897	3/18/2015 First: 4/16/2013
S- Ref 10145 - …direct the ERO to modify IRO-002-1 to require a minimum set of tools that must be made available to the reliability coordinator.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 905	5/26/2016
S- Ref 10146 - …direct that the ERO develop a modification to the Reliability Standard through the Reliability Standards development process to create criteria to define the term "critical facilities" in a reliability coordinator's area and its adjacent systems.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 914	3/18/2015
S- Ref 10147 - Consider the suggestions of APPA, Entergy, and Xcel when doing so.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 914	3/18/2015
S- Ref 10148 - …direct the ERO to modify IRO-004-1 through the Reliability Standards development process to require the next-day analysis to identify control actions that can be implemented and effective within 30 minutes after a contingency.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 935	3/18/2015 First: 4/16/2013

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S- Ref 10149 - In response to APPAs concern that NERC did not provide a Measure for each Requirement, we reiterate that it is in the EROs discretion whether each Requirement requires a corresponding Measure. The ERO should consider this issue through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 934	3/18/2015 First: 4/16/2013
S- Ref 10150 - Provide further clarification that reliability coordinators and transmission operators direct control actions, not LSEs as part of the standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 950	3/18/2015 First: 4/16/2013
S- Ref 10151 - …direct the ERO to develop a modification to IRO-005-1 through the Reliability Standards development process that includes Measures and Levels of Non-Compliance.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 951	11/15/2006
S- Ref 10152 - ...direct that the Measures and Levels of Non-Compliance specific to IROL violations must be commensurate with the magnitude, duration, frequency and causes of the violations and whether these occur during normal or contingency conditions.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 951	3/18/2015 First: 4/16/2013
S- Ref 10153 - ...direct the ERO to conduct a survey on IROL practices and actual operating experiences by requiring reliability coordinators to report any violations of IROL, their causes, the date and time, the durations and magnitudes in which actual operations exceeds IROLs to the ERO on a monthly basis for one year beginning two months after the effective date of the Final Rule.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 951	10/31/2008
S- Ref 10154 - ...direct the ERO to develop a modification to IRO-006-3 through the Reliability Standards development process that includes a clear warning that the TLR procedure is an inappropriate and ineffective tool to mitigate actual IROL violations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 964	12/21/2007

Table 3: Directives by Commission Order						
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S- Ref 10155 - ...direct the ERO to develop a modification to IRO-006-3 through the Reliability Standards development process that identifies in a Requirement the available alternatives to mitigate an IROL violation other than use of the TLR procedure.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 964	12/21/2007
S- Ref 10156 - ... direct the ERO to modify the WECC and ERCOT procedures to ensure consistency with the standard form of the Reliability Standards including Requirements, Measures and Levels of Non-Compliance.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 964	9/11/2008
S- Ref 10157 - In addressing MISO-PJMs claim that the ERO should modify IRO-006-3 and the MISO-PJM regional difference to require netting generation-to-load impacts to recognize counterflow, we will let the ERO Operating Subcommittee address the technical merits of netting flow impacts in the interchange distribution calculator.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 992	Not Standards' Related (OC PC SubC) 12/10/2014
S- Ref 10158 - Consider the suggestions of MidAmerican and Xcel when developing the modification.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 964	12/21/2007
S- Ref 10159 - ...direct that the ERO, within 15 days of the effective date of this Final Rule, submit a filing that provides an explanation regarding specific language of Requirements R1 and R1.1 of IRO-006-4.	Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards	7/21/2008	Order 713	RM08-7-000	Para 46	9/11/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10160 - ...direct the ERO to provide an explanation regarding the phrase [t]he TLR procedure alone is an inappropriate and ineffective tool to mitigate an IROL violation.	Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards	7/21/2008	Order 713	RM08-7-000	Para 50 Sen 3	9/11/2008
S- Ref 10161 - Further, the ERO should explain whether Requirements R1 and R1.1 only allow the TLR procedure to be continued when already deployed prior to an actual IROL violation or, alternatively, whether Requirements R1 and R1.1 allow use of the TLR procedure as a tool to address actual violations after they occur.	Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards	7/21/2008	Order 713	RM08-7-000	Para 50	9/11/2008
S- Ref 10162 - ...direct the ERO to develop a modification of Requirement R1.1 with respect to the term alone, consistent with this discussion.	Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards	3/19/2009	Order 713-A	RM08-7-000 and RM08-7-001	Para 36	1/13/2011

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10163 - ...direct the ERO to modify the violation risk factors of Requirements R1 through R4 of IRO-006-4 to high.	Modification of Interchange and Transmission Loading Relief Reliability Standards; and Electric Reliability Organization Interpretation of Specific Requirements of Four Reliability Standards	3/19/2009	Order 713-A	RM08-7-000 and RM08-7-001	Para 59	1/13/2011
S- Ref 10164 - Provide a framework for ATC, TTC, and ETC calculation, developing industry-wide consistency of all ATC components. Three methodologies are expected: contract path ATC, network ATC, and network AFC.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1029	11/21/2008
S- Ref 10165 - ...direct that WECC in developing a permanent, replacement Reliability Standard, clarify the term receiver and the applicability of the standard.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 70	7/8/2009
S- Ref 10166 - ...direct WECC to address PPLs concerns in developing a permanent, replacement regional Reliability Standard.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 71	7/8/2009
S- Ref 10167 - ...expect that WECC, in developing a permanent, replacement regional Reliability Standard, will address the shortcomings identified by NERC.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 110	7/8/2009
S- Ref 10168 - ... direct the ERO to modify Reliability Standard MOD-001-0 to require disclosure of the algorithms and processes used in ATC calculation. In addition, consistent with Order No. 890, the Commission believes that further clarification is necessary regarding the ATC calculation algorithm for firm and non-firm ATC.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1036	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10169 - …direct the ERO to modify MOD-001-0 to ensure that the following data, at a minimum, be exchanged among transmission providers for the purposes of ATC modeling: (1) load levels; (2) transmission planned and contingency outages; (3) generation planned and contingency outages; (4) base generation dispatch; (5) existing transmission reservations, including counterflows; (6) ATC recalculation frequency and times and (7) source/sink modeling identification.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1038	11/21/2008
S- Ref 10170 - Include a requirement that assumptions used in the ATC and AFC calculations should be consistent with those used for planning the expansion of or operation of the bulk power system.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1039	11/21/2008
S- Ref 10171 - …direct the ERO to develop requirements in Reliability Standard MOD-001-0 that specify: (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1042	11/21/2008
S- Ref 10172 - ...direct the ERO to develop AFC/TFC definitions and requirements used to identify a particular set of transmission facilities as flowgates.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1031	11/21/2008
S- Ref 10173 - ...direct the ERO to consider development of a requirement that the transmission service provider declare what type of contingencies it uses for specific calculations of ATC/AFC and TTC/TFC, and release the contingency files upon request if not submitted with the data filed with the ERO in compliance with MOD-010-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1046	11/21/2008
S- Ref 10174 - Focus of ATC/AFC with this standard; FAC-012-1 should focus on TTC/TFC.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1057	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10175 - Identify applicable entities in terms of users, owners, and operators of the bulk power system.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1056	11/21/2008
S- Ref 10176 - ...direct the ERO to develop AFC/TFC definitions and requirements used to identify a particular set of transmission facilities as flowgates.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1031	11/21/2008
S- Ref 10177 - ...direct the ERO to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1032	11/21/2008
S- Ref 10178 - Accordingly, we find that reservations that have the same point of receipt (POR) (generator) but different point of delivery (POD) (load), for the same time frame, should not be modeled in the ETC calculation simultaneously if their combined reserved transmission capacity exceeds the generator's nameplate capacity at a POR.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1033	11/21/2008
S- Ref 10179 - ...direct the ERO to modify MOD-001-0 to provide a framework for ATC, TTC and ETC calculation that, consistent with the discussion above: (1) requires industry-wide consistency of all ATC components and certain data inputs and exchange, modeling assumptions, calculation frequency, and coordination of data relevant for the calculation of ATC; (2) provides predictable and sufficiently accurate, consistent, equivalent, and replicable ATC calculations regardless of the methodology used by the region; (3) provides the definition of AFC and method for its conversion to ATC; (4) lays out clear instructions on how ETC should be defined and (5) identifies to whom MOD-001-0 Reliability Standards apply, i.e., users, owners and operators of the Bulk-Power System.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1034	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10181 - ...direct the ERO to modify Reliability Standard MOD-001-0 to require disclosure of the algorithms and processes used in ATC calculation, and also to implement the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the transmission provider shall account only for firm commitments and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected service, unscheduled service and counterflows.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1036	11/21/2008
S- Ref 10182 - ...direct the ERO to develop consistent requirements for modeling load levels in MOD-001-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1040	11/21/2008
S- Ref 10183 - …direct the ERO to revise Reliability Standard MOD-001-0 by specifying that base generation dispatch will model: (1) all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run and (2) all uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1041	11/21/2008
S- Ref 10184 - …direct the ERO to develop requirements in Reliability Standard MOD-001-0 that specify: (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1042	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10185 - ...direct the ERO to modify Reliability Standard MOD-001-0 to require ATC to be updated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, e.g., generation and transmission outages, load forecasts, interchange schedules, transmission reservations, facility ratings and other necessary data.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1043	11/21/2008
S- Ref 10186 - …direct the ERO to develop in MOD-001-0 a requirement that each transmission service provider provide on OASIS its OATT Attachment C, in which Order No. 890 requires transmission providers to include a detailed description of the specific mathematical algorithm the transmission provider uses to calculate both firm and non-firm ATC for various time frames such as: (1) the scheduling horizon (same day and real-time), (2) operating horizon (day ahead and pre-schedule) and (3) planning horizon (beyond the operating horizon). In addition, a transmission provider must include a process flow diagram that describes the various steps that it takes in performing the ATC calculation.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1047	11/21/2008
S- Ref 10187 - ...direct public utilities, working through NERC, to develop an AFC definition and requirements used to identify a particular set of transmission facilities as a flowgate. However, we remind transmission providers that our regulations require the posting of ATC values associated with a particular path, not AFC values associated with a flowgate.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 211	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10188 - ...direct public utilities, working through NERC, to modify related ATC standards by implementing the following principles for firm and non-firm ATC calculations: (1) for firm ATC calculations, the transmission provider shall account only for firm commitments; and (2) for non-firm ATC calculations, the transmission provider shall account for both firm and non-firm commitments, postbacks of redirected services, unscheduled service, and counterflows.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 212	11/21/2008
S- Ref 10189 - With respect to a timeline for completion, the Commission concurs with NERC that a significant amount of work remains to be done on ATC-related reliability standards development.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 223	11/21/2008
S- Ref 10190 - The Commission adopts the NOPR proposal and directs public utilities, working through NERC, to develop consistent practices for calculating TTC/TFC. We direct public utilities, working through NERC, to address, through the reliability standards process, any differences in developing TTC/TFC for transmission provided under the pro forma OATT and for transfer capability for native load and reliability assessment studies.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 237	11/21/2008
S- Ref 10191 - …direct public utilities, working through NERC and NAESB, to develop a consistent approach for determining the amount of transfer capability a transmission provider may set aside for its native load and other committed uses.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 243	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10192 - …determine that ETC should be defined to include committed uses of the transmission system, including (1) native load commitments (including network service), (2) grandfathered transmission rights, (3) appropriate point-to-point reservations,170 (4) rollover rights associated with long-term firm service, and (5) other uses identified through the NERC process. ETC should not be used to set aside transfer capability for any type of planning or contingency reserve, which are to be addressed through CBM and TRM.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 244	11/21/2008
S- Ref 10193 - …direct public utilities, working through NERC, to develop requirements in MOD-001 that lay out clear instructions on how these reservations should be accounted.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 245	11/21/2008
S- Ref 10194 - We find that requiring consistency in the data and modeling assumptions used for ATC calculations will remedy the potential for undue discrimination by eliminating discretion and ensuring comparability in the manner in which a transmission provider operates and plans its system to serve native load and the manner in which it calculates ATC for service to third parties. The Commission directs public utilities, working through NERC, to modify ATC standards to achieve this consistency.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 292	11/21/2008
S- Ref 10195 - ...reiterate that public utilities, working through NERC and NAESB, are directed to develop an approach for accounting for counterflows, in the relevant ATC standards and business practices.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 293	11/21/2008
S- Ref 10196 - ...we direct public utilities, working through NERC, to develop consistent requirements for modeling load levels in MOD-001 for the services offered under the pro forma OATT.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 295	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10197 - ...direct public utilities, working through NERC, to revise reliability standard MOD-001 by specifying that base generation dispatch will model (1) all designated network resources and other resources that are committed or have the legal obligation to run, as they are expected to run and (2) uncommitted resources that are deliverable within the control area, economically dispatched as necessary to meet balancing requirements.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 296	11/21/2008
S- Ref 10198 - …direct public utilities, working through NERC, to develop requirements in reliability standard MOD-001 that specify (1) a consistent approach on how to simulate reservations from points of receipt to points of delivery when sources and sinks are unknown and (2) how to model existing reservations.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 297	11/21/2008
S- Ref 10199 - …direct public utilities, working through NERC and NAESB, to revise reliability standard MOD-001 to require ATC to be recalculated by all transmission providers on a consistent time interval and in a manner that closely reflects the actual topology of the system, e.g., generation and transmission outages, load forecast, interchange schedules, transmission reservations, facility ratings, and other necessary data.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 301	11/21/2008
S- Ref 10200 - ... direct public utilities, working through NERC, to revise the related MOD reliability standards to require the exchange of data and coordination among transmission providers and, working through NAESB, to develop complementary business practices.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 310	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10201 - ...We also acknowledge TVA's comments that the NERC standards drafting team is developing standards that should address "double counting" in ATC calculations in general. However, we require that the information in Attachment C be sufficient to demonstrate that a transmission provider is not double counting CBM in its ATC calculation.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 338	11/21/2008
S- Ref 10202 - We affirm our statement in the NOPR proposal acknowledging that transfer capability associated with transmission reservations that are not scheduled in real time is required to be made available as non-firm, and posted on OASIS.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 389	11/21/2008
S- Ref 10204 - directs the ERO to modify the Reliability Standards so as to increase the document retention requirements to a term of five years, in order to be consistent with the enforcement provisions established in Order No. 670.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 129	2/10/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10206 - ...directs the ERO to develop a modification to the Reliability Standards pursuant to the EROs Reliability Standards development process to require disclosure of the various implementation documents to any registered entity who demonstrates to the ERO a reliability need for such information.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 151	2/10/2014
S- Ref 10207 - ...consider generator nameplate ratings and transmission line ratings including the comments raised by Entegra and ISO/RTO Council.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	Order No. 788 RM13-8-000	Para 160	2013 N/A - Withdrawn by FERC Order No. 788

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10208 - ...directs the ERO to develop benchmarking and updating requirements to measure modeled available transfer and flowgate capabilities against actual values.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 162	2/10/2014
S- Ref 10209 - ...directs the ERO, pursuant to section 215(d)(5) of the FPA and section 39.5(f) of our regulations, to develop a modification to MOD-028-1 and MOD-029-1 to specify that base generation schedules used in the calculation of available transfer capability will reflect the modeling of all designated network resources and other resources that are committed to or have the legal obligation to run, as they are expected to run, and to address the effect on available transfer capability of designating and undesignating a network resource.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 173	2/10/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10211 - ...directs the ERO to consider Entegras request regarding more frequent updates for constrained facilities through its Reliability Standards development process (see paragraph 177 of Order 729 for Entegra's comments).	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	Order No. 788 RM13-8-000	Para 179	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10212 - ...directs the ERO to develop modifications to MOD-001-1 and MOD-030-2 to clarify that material changes in system conditions will trigger an update whenever practical (see also paragraph 23 of Order 729-A).	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 179 Sen 5	2/10/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10214 - …directs the ERO to develop modifications to MOD-001-1 pursuant to the EROs Reliability Standards development process to prevent the double-counting of data inputs and assumptions.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 184	2/10/2014
S- Ref 10215 - ...directs the ERO to develop a modification to the Reliability Standard pursuant to its Reliability Standards development process requiring transmission service providers to include in their implementation documents any inconsistent modeling practices along with a justification for such inconsistencies"	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 192	2/10/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10216 - ...encourage the ERO to consider Midwest ISOs and Entegras comments when developing other modifications to the MOD Reliability Standards pursuant to the EROs Reliability Standards development procedure.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	Order No. 788 RM13-8-000	Para 200	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10217 - ...direct the ERO to develop a modification to Requirements R3.1 and R.4.1 of MOD-004-1 to require load-serving entities and resource planners to determine generation capability import requirements by reference to one or more relevant studies (loss of load expectation, loss of load probability or deterministic risk analysis) and applicable reserve margin or resource adequacy requirements, as relevant.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 220	2/10/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10218 - ...direct the ERO to modify MOD-004-1 to clarify the term manage in Requirement R1.3. This modification should ensure that the Reliability Standard clarify how the transmission service provider will manage situations where the requested use of capacity benefit margin exceeds the capacity benefit margin available.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 222	2/10/2014
S- Ref 10219 - ...direct the ERO to develop a modification sub-requirement R2.2 pursuant to its Reliability Standards development process to clarify the phrase adjacent and beyond Reliability Coordination areas.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	Order No. 788 RM13-8-000	Para 231	2013 N/A - Withdrawn by FERC Order No. 788

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10220 - The Commission agrees that a graduated time frame for reposting could be reasonable in some situations. Accordingly, the ERO should consider this suggestion when making future modifications to the Reliability Standards.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	Order No. 788 RM13-8-000	Para 234	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10221 - ...direct the ERO to develop a modification to MOD-028-1 pursuant to its Reliability Standards development process to address these two concerns.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 237	2/10/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10222 -...consider Puget Sound's concerns on this issue when making future modifications to the Reliability Standards.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	Order No. 788 RM13-8-000	Para 246	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10223 - …direct the ERO to make explicit such [effective date] detail in any future version of this or any other Reliability Standard.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	Order No. 788 RM13-8-000	Para 269	2013 N/A - Withdrawn by FERC Order No. 788

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10224 - …direct the ERO to file revised violation severity levels and violation risk factors no later than 120 days before the Reliability Standards become effective.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 274	12/1/2010
S- Ref 10226 - ...direct the ERO to develop a modification to the definition of Postback to eliminate the reference to Business Practices.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 304	2/10/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10227 - ...direct the ERO to develop a modification to the definition of Business Practices that would remove the reference to regional reliability organizations and replace it with the term Regional Entity.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 305	2/10/2014
S- Ref 10229 - ...direct the ERO to develop a modification to the definition of ATC Path that does not reference the Commissions regulations.	Mandatory Reliability Standards for the Calculation of Available Transfer Capability, Capacity Benefit Margins, Transmission Reliability Margins, Total Transfer Capability, and Existing Transmission Commitments and Mandatory Reliability Standards for the BPS	11/24/2009	Order 729	RM08-19-000	Para 306	2/10/2014
S- Ref 10230 - …direct the ERO to consider APPA's suggestion that MOD-003-0 may be redundant and should be eliminated if the ERO develops a modification to the MOD-001-0 Reliability Standard through the Reliability Standards development process that includes reporting requirements.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1066	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10231 - Clarify that CBM shall be set aside upon request of any LSE within a balancing area to meet its verifiable historical, state, RTO, or regional generation reliability criteria.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1077	11/21/2008
S- Ref 10232 - ...direct the ERO to develop Requirements regarding transparency of the generation planning studies used to determine CBM values.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1077	11/21/2008
S- Ref 10233 - Make clear the process for how CBM is allocated across transmission paths or flowgates.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1082	11/21/2008
S- Ref 10234 - We share TAPS's concern that there is a significant potential for abuse as a result of the current flexibility afforded to transmission providers in the calculation of both CBM and TRM. In response to TAPS's concern, we clarify that in accordance with the OATT Reform Final Rule and the ERO CBM definition, each LSE has the right to request CBM be set aside and use it to meet its verifiable historical, state, RTO or regional generation reliability criteria requirement such as reserve margin, loss of load probability, loss of largest units, etc. As such, the LSEs that request CBM be set aside must be identified as applicable entities with identified Requirements, including Requirements on generation studies to verify the set aside, Measures and Levels of Non-Compliance. We direct the ERO to modify the Reliability Standard accordingly.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1080	11/21/2008
S- Ref 10235 - ...believe this Reliability Standard should be modified to include a provision ensuring that CBM, TRM and ETC cannot be used for the same purpose, such as loss of the identical generating unit.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1079	11/21/2008
S- Ref 10236 - Coordinate with NAESB business practices.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1081	11/21/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10237 - Consider APPAs suggestion that MOD-004 may be redundant and could be eliminated if MOD-002 is modified to include reporting requirements.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1083	11/21/2008
S- Ref 10238 - ...direct the ERO to provide more specific requirements for how CBM should be determined and allocated across transmission paths or flowgates.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1078	11/21/2008
S- Ref 10239 - The Commission concludes that it is appropriate to allow LSEs to retain the option of setting aside transfer capability in the form of CBM to maintain their generation reliability requirement. We agree with commenters that, without CBM, LSEs would have to increase their generation reserve margins by contracting for generation capacity, which may result in higher costs without additional reliability benefits. We require, however, the development of standards for how CBM is determined, allocated across transmission paths, and used in order to limit misuse of transfer capability set aside as CBM. Transmission providers also must reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service to ensure comparable treatment for point-to-point to customers.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 256	11/21/2008
S- Ref 10240 - ...expect verification of the CBM values to be part of the Requirements with appropriate Measures and Levels of Non-Compliance.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1077	11/21/2008

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S- Ref 10241 - The Commission therefore adopts a combination of the NOPR options one and two, and declines to adopt option three. First, we require public utilities, working through NERC and NAESB, to develop clear standards for how the CBM value shall be determined, allocated across transmission paths, and used. We understand that NERC has already begun the process of modifying several of the CBM-related reliability standards and that the drafting process is a joint project with NAESB. Second, we require transmission providers to reflect the set-aside of transfer capability as CBM in the development of the rate for point-to-point transmission service.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 257	11/21/2008
S- Ref 10242 - To ensure CBM is used for its intended purpose, CBM shall only be used to allow an LSE to meet its generation reliability criteria. Consistent with Duke's statement, we clarify that each LSE within a transmission provider's control area has the right to request the transmission provider to set aside transfer capability as CBM for the LSE to meet its historical, state, RTO, or regional generation reliability criteria requirement such as reserve margin, loss of load probability (LOLP), the loss of largest units, etc.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 259	11/21/2008
S- Ref 10243 - …direct public utilities, working through NERC, to develop clear requirements for allocating CBM over transmission paths and flowgates.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 260	11/21/2008
S- Ref 10244 - We concur with TAPS proposal that all LSEs should have access to CBM and meaningful input into how much transfer capability is set aside as CBM.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 261	11/21/2008

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S- Ref 10245 - ...direct public utilities working through NERC to modify the CBM-related standards to specify the generation deficiency conditions during which an LSE will be allowed to use the transfer capability reserved as CBM.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 262	11/21/2008
S- Ref 10246 - The Commission also adopts the NOPR proposal to establish standards specifying the appropriate uses of TRM to guide NERC and NAESB in the drafting process.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 273	11/21/2008
S- Ref 10247 - We concur with TAPS' proposal that all LSEs should have access to CBM and meaningful input into how much transfer capability is set aside as CBM.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 354	11/21/2008
S- Ref 10248 - The Commission incorporates into its regulations the requirement in the CBM Order for a transmission provider to periodically reevaluate its transfer capability set aside for CBM. With respect to TAPS' concerns over the effort involved in the reevaluation process, we will require CBM studies to be performed at least every year. This requirement is consistent with the CBM Order, in which the Commission stated that the level of ATC set aside for CBM should be reevaluated periodically to take into account more certain information (such as assumptions that may not have, in fact, materialized).	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 358	11/21/2008

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S- Ref 10249 - While changes requiring a reevaluation of CBM are longer-term in nature (e.g., installation of a new generator or a long-term outage), quarterly may be too frequent, though two years may be too long and may prevent a portion of the CBM set-aside from being released as ATC. Moreover, annual reevaluation is consistent with the current NERC standard being developed in MOD-005. The requirement to evaluate CBM at least every year also is consistent with the CBM Order in that the Commission directed transmission providers to periodically reevaluate their generation reliability needs so as to make known the need for CBM and to post on OASIS their practices in this regard.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 358	11/21/2008
S- Ref 10250 - Consider APPAs comment to incorporate MOD-004 and MOD-005 into MOD-006 through the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1088	11/21/2008
S- Ref 10251 - …direct the ERO to modify its standard to prevent use of CBM and TRM for the same purposes.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1098	11/21/2008
S- Ref 10252 - ...direct the ERO to modify Requirement R1.2 so that a transmission constraint is not a required condition for CBM usage.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1099	11/21/2008
S- Ref 10253 - ...direct the ERO to modify the Reliability Standard to include a specific energy emergency alert level that will trigger CBM usage.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1100	11/21/2008
S- Ref 10254 - We also reiterate the direction in Order No. 890 that CBM should have a zero value in the calculation of non-firm ATC because non-firm service may be curtailed so that CBM can be used.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1101	11/21/2008

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S- Ref 10255 - We also adopt the NOPR proposal to require the applicability section to include the entities that actually use CBM, such as LSEs…direct the ERO to modify the standard accordingly.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1103	11/21/2008
S- Ref 10256 - ...direct that CBM may be implemented up to the reserved value when a LSE is facing firm load curtailments.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1101	11/21/2008
S- Ref 10257 - We adopt the NOPR proposal that CBM should be used only when the LSEs local generation capacity is insufficient to meet balancing Reliability Standards, with the clarification that the local generation is that generation capacity that is either owned or contracted for by the LSE.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1102	11/21/2008
S- Ref 10258 - ...direct the ERO to modify the standard to include the entities that actually use CBM, such as LSEs.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1110	11/21/2008
S- Ref 10259 - ...direct the ERO to include balancing authorities within the entities to which this standard is applicable.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1110	11/21/2008
S- Ref 10260 - ...directs the ERO to modify standard MOD-008-0 to clarify how TRM should be calculated and allocated across paths or flowgates.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1122	11/21/2008
S- Ref 10261 - ...directs the ERO to specify the parameters for entities to use in determining uncertainties for which TRM can be set aside	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1122	11/21/2008
S- Ref 10262 - ...direct the ERO to develop requirements regarding transparency of the documentation that supports TRM determination.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1123	11/21/2008
S- Ref 10263 - …should revise the applicability section of this standard to add planning authorities and reliability coordinators, and in addition, any other entities that may be identified in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1124	11/21/2008

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S- Ref 10264 - The Commission adopts the NOPR proposal and requires public utilities, working through NERC, to complete the ongoing process of modifying TRM standards MOD-008 and MOD-009.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 272	11/21/2008
S- Ref 10265 - ...direct public utilities, working through NERC, to establish an appropriate maximum TRM.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 275	11/21/2008
S- Ref 10266 - ... direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the information related to data gathering, data maintenance, reliability assessments and other process-type functions.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1147	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10267 - ...direct the ERO to modify MOD-010-0 to require filing of all of the contingencies that are used in performing steady-state system operation and planning studies.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1148	2/25/2014
S- Ref 10268 - ...direct the ERO to address confidentiality issues and modify the Reliability Standard as necessary through its Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1152	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10269 - ...direct the ERO to modify MOD-010-0 to include transmission operators as an applicable entity.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1154	2/25/2014
S- Ref 10270 - ...direct the ERO to develop a Work Plan that will facilitate ongoing collection of the steady-state modeling and simulation data specified in MOD-011-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1163	2013 N/A - Withdrawn by FERC Order No. 788

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S- Ref 10271 - We adopt our NOPR proposal that the planning authority should be included in this Reliability Standard because the planning authority is the entity responsible for the coordination and integration of transmission facilities and resource plans, as well as one of the entities responsible for the integrity and consistency of the data.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1155	2/25/2014
S- Ref 10272 - ...directs public utilities, working through NERC, to modify the reliability standards MOD-010 through MOD-025 to incorporate a requirement for the periodic review and modification of models for (1) load flow base cases with contingency, subsystem, and monitoring files, (2) short circuit data, and (3) transient and dynamic stability simulation data, in order to ensure that they are up to date.	Preventing Undue Discrimination and Preference in Transmission Service	2/16/2007	Order 890	RM05-17-000 and RM05-25-000	Para 290	2/25/2014
S- Ref 10273 - ...direct the ERO to add the planning authority to the applicability section of this Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1162	2/25/2014
S- Ref 10274 - Develop a work plan and submit a compliance filing that will facilitate the ongoing collection of the steady-state modeling and simulation data specified in this standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1163	Resolved 1/1/2012
S- Ref 10275 - ...direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entities the information related to data gathering, data maintenance, reliability assessments and other process type functions.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1177	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10276 - ...direct the ERO to modify MOD-012-0 by adding a new requirement to provide a list of the faults and disturbances used in performing dynamics system studies for system operation and planning.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1178	2/25/2014

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S- Ref 10277 - ...direct the ERO to address confidentiality issues and modify the standard as necessary through its Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1181	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10278 - ...direct the ERO to modify MOD-012-0 to require the transmission planner to provide fault and disturbance lists.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1183	2/25/2014
S- Ref 10279 - As we will discuss in the next section on MOD-013-1, we require the ERO to develop a Work Plan and submit a compliance filing that will facilitate ongoing collection of the dynamics system modeling and simulation data specified by the deferred MOD-013-1 Reliability Standard, which is necessary for implementation of MOD-012-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1177	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10280 - …direct the ERO to modify the Reliability Standard to permit entities to estimate dynamics data if they are unable to obtain unit specific data for any reason, not just for units constructed prior to 1990.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1197	2/25/2014
S- Ref 10281 - ...directs that this Reliability Standard be modified to require that the results of these dynamics models be compared with actual disturbance data to verify the accuracy of the models.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1197	2/25/2014
S- Ref 10282 - ...directs the ERO to expand the applicability section in MOD-013-1 to include planning authorities because they are the entities responsible for the coordination and integration of transmission facilities and resource plans.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1199	2/25/2014
S- Ref 10283 - Develop a work plan and submit a compliance filing that will facilitate the ongoing collection of the dynamics modeling and simulation data specified in this standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1200	2013 N/A - Withdrawn by FERC Order No. 788

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S- Ref 10284 - ...direct the ERO to add the planning authority to the list of applicable entities.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1184	2/25/2014
S- Ref 10286 - ...direct the ERO to modify the Reliability Standard to include a requirement that the models be validated against actual system responses.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1210	2/25/2014
S- Ref 10287 - ...direct the ERO to modify MOD-014-0 through the Reliability Standards development process to require that actual system events be simulated and if the model output is not within the accuracy required, the model shall be modified to achieve the necessary accuracy.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1211	2/25/2014
S- Ref 10288 - …direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide the validated models to regional reliability organizations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1212	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10289 - …direct the ERO to develop a Work Plan that will facilitate ongoing validation of steady-state models and submit a compliance filing containing the Work Plan with the Commission.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1212	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10290 - ...direct the ERO to modify the standard to require actual system events be simulated and dynamics system model output be validated against actual system responses.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1220	2/25/2014
S- Ref 10291 - ...direct the ERO to require users, owners and operators to provide to the Regional Entity the validated dynamics system models while MOD-015-0 is being modified.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1221	2013 N/A - Withdrawn by FERC Order No. 788

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S- Ref 10292 - …develop a work plan that will facilitate ongoing validation of dynamics models and submit a compliance filing to the Commission.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1221	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10293 - …direct the ERO to add to its definition of DSM "any other entities" that undertake activities or programs to influence the amount or timing of electricity they use without violating other Reliability Standard Requirement.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1232	5/13/2014
S- Ref 10294 - ...directs the ERO to modify MOD-016-1 and expand the applicability section to include the transmission planner, on the basis that under the NERC Functional Model the transmission planner is responsible for collecting system modeling data, including actual and forecast load, to evaluate transmission expansion plans.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1232	5/13/2014
S- Ref 10295 - …directs the ERO to modify the Reliability Standard to require reporting of temperature and humidity along with peak load because actual load must be weather normalized for meaningful comparison with forecasted values.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1249	5/13/2014
S- Ref 10296 - ...direct the ERO to modify the Reliability Standard to require reporting of the accuracy, error and bias of load forecasts compared to actual loads with due regard to temperature and humidity variations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1251	5/13/2014
S- Ref 10297 - ...direct the ERO to add a Requirement that addresses correcting forecasts based on prior inaccuracies, errors and bias.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1252	5/13/2014
S- Ref 10298 - Expand the applicability of MOD-017 to include transmission planners.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1255	5/13/2014

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10299 - …direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified under standards that are deferred, and believe there should be no difficulty complying with this Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1247	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10300 - We agree, however, with APPA that certain types of load are not sensitive to temperature and humidity. We therefore find that the ERO should address Alcoa's concerns in its Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1250	5/13/2014
S- Ref 10302 - ...directs the ERO to consider MISOs concerns in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1256 Sen 3	5/13/2014
S- Ref 10303 - ...direct the ERO to provide a Work Plan and compliance filing regarding the collection of information specified for standards that are deferred, and believe there should be no difficulties complying with this Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1264	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10304 - Regarding TAPSs concern that small entities should not be required to comply with MOD-018-0 because their forecasts are not significant for system reliability purposes, the Commission directs the ERO to address this matter in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1265	5/13/2014
S- Ref 10305 - Require users, owners, and operators to provide to the regional entity information related to forecasts of interruptible demands and direct control load management.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1275	2013 N/A - Withdrawn by FERC Order No. 788

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10306 - Require reporting of the accuracy, error, bias of controllable load forecasts. The Commission adopts the NOPR proposal directing the ERO to modify this standard to require reporting of the accuracy, error and bias of controllable load forecasts.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1276	5/13/2014
S- Ref 10307 - ...direct the ERO to include APPAs proposal in the Reliability Standards development process to add a new requirement to MOD-019-0 that would oblige resource planners to analyze differences between actual and forecasted demands for the five years of actual controllable load and identify what corrective actions should be taken to improve controllable load forecasting for the 10-year planning horizon.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1277	5/13/2014
S- Ref 10308 - ...directs the ERO to develop a modification to MOD-020-0 through the Reliability Standards development process to require reporting of the accuracy, error and bias of controllable load forecasts.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1287	5/13/2014
S- Ref 10309 - ...direct the ERO to provide a Work Plan and compliance filing regarding collection of information specified under related standards that are deferred, and believe there should be no difficulty complying with this Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1297	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10310 - ...direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1298	5/13/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10311 - ...direct the ERO to modify this Reliability Standard to allow resource planners to analyze the causes of differences between actual and forecasted demands, and to identify any corrective actions that should be taken to improve forecasted demand responses for future forecasts. Therefore, we adopt the NOPR proposal and direct the ERO to modify MOD-021-0 by adding a requirement for standardization of principles on reporting and validating DSM program information.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1298	5/13/2014
S- Ref 10312 - …directs the ERO to modify the title and purpose statement to remove the word controllable.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1300	9/9/2010
S- Ref 10313 - ...direct the ERO to use its authority pursuant to 39.2(d) of our regulations to require users, owners and operators to provide to the Regional Entity the information required by this Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1297	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10314 - ...direct the ERO to use its authority pursuant to § 39.2(d) of our regulations to require users, owners and operators to provide this information.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1312	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10315 - Document test conditions and the relationships between test conditions and generator output so that the amount of power that can be expected to be delivered from a generator at different conditions can be determined.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1310	5/30/2013

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10316 - Clarify requirement R2 that specifies that the regional reliability organization shall provide generator gross and net real power capability verification within 30 calendar days of approval. The confusion centers on approval and when the 30-day period starts. Therefore, we direct the ERO to modify this Reliability Standard by adding information that will clarify this requirement.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1311	5/30/2013
S- Ref 10317 - Provide a work plan and compliance filing regarding the collection of information specified for standards that are deferred.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1308	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10318 - Similarly, we respond to Constellation that any modification of the Levels of Non-Compliance in this Reliability Standard should be reviewed in the ERO Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1310	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10319 - Require verification of reactive power capability at multiple points over a units operating range.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1321	11/21/2013
S- Ref 10320 - We maintain the concern we expressed in the NOPR that Requirement R2 provides that the "regional reliability organization shall provide generator gross and net reactive power capability verification within 30 calendar days of approval" and note that it is not clear what approval is required and when the 30-day period starts. We direct the ERO to provide clarification on this requirement.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1322	5/30/2013

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S- Ref 10321 - The Commission will not approve or remand MOD-025-1 until the ERO submits additional information. In order to continue verifying and reporting gross and net reactive power generating capability needed for reliability assessment and future plans, we direct the ERO to develop a Work Plan as defined in the Common Issues section.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1320	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10322 - Clearly, in a region where an RTO or ISO performs the transmission operator function, its personnel with primary responsibility for real-time operations must receive formal training pursuant to PER-002-0. In addition, personnel who are responsible for implementing instructions at a local control center also affect the reliability of the Bulk Power System. These entities may take independent action under certain circumstances, for example, to protect assets, personnel safety and during system restorations. Whether the RTO or the local control center is ultimately responsible for compliance is a separate issue addressed above, but regardless of which entity registers for that responsibility, these local control center employees must receive formal training consistent with their roles, responsibilities and tasks. Thus, while we direct the ERO to develop modifications to PER-002-0 to include formal training for local control center personnel, that training should be tailored to the needs of the positions.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1343	9/30/2009
S- Ref 10323 - ...directs the ERO to develop a modification to PER-002-0 that extends applicability to the operations planning and operations support staff of transmission operators and balancing authorities, as clarified below.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1372	3/7/2014

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S- Ref 10324 - …direct that the ERO develop a modification to PER-002-2 (or a new Reliability Standard) that uses the SAT methodology.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1382	9/30/2009
S- Ref 10326 - ... directs the ERO to explore the feasibility of developing meaningful performance metrics for assessing the effectiveness of training programs, and if feasible, to develop such metrics for the Reliability Standard as part of the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1379	9/30/2009
S- Ref 10327 - ...direct the ERO to consider, through the Reliability Standards development process, whether personnel that perform these additional functions should be included in mandatory training pursuant to PER-002-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1373	3/7/2014
S- Ref 10328 - Consider FirstEnergy's comments regarding the nuclear plant operators training program as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1364	9/30/2009
S- Ref 10329 - Training programs for operations planning and operations support staff must be tailored to the needs of the function, the tasks performed and personnel involved.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1375	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10330 - ...direct the ERO to develop specific Requirements addressing the scope, content and duration appropriate for generator operator.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1363	3/7/2014
S- Ref 10331 - This does not mean that these entities must develop and maintain full-scale simulators but rather they should have access to training on simulators... Accordingly, the Commission directs the ERO to develop a requirement for the use of simulators dependent on the entity's role and size, as discussed above.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1391	9/30/2009

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S- Ref 10332 - ...many commenters acknowledged the need to have clear training expectations and training programs tailored to specific job functions. The Commission finds that these two modifications will enhance the training by focusing on expectations and tailoring the training to specific job functions; therefore, the Commission adopts these modifications to the Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1392	9/30/2009
S- Ref 10333 - …direct the ERO to specify the minimum competencies that must be demonstrated to become and remain a certified operator.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1408	4/29/2011
S- Ref 10334 - ...direct the ERO to consider grandfathering certification requirements for these personnel so that the industry can retain the knowledge and skill of these long tenured operators.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1407	4/29/2011
S- Ref 10335 - The Commission finds that these modifications will improve the Reliability Standard because they include training requirements for the reliability coordinator who has the highest level of authority to assure Reliable Operation of the Bulk-Power System. Accordingly, the Commission directs the ERO to develop modifications to the Reliability Standard that address these matters.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1415	9/30/2009
S- Ref 10336 - Consider the suggestions of FirstEnergy and Xcel as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1417	9/30/2009

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10337 - ... directs the ERO to develop a modification through the Reliability Standards development process to PER-004-1 that: (1) includes formal training requirements for reliability coordinators similar to those addressed under the personnel training Reliability Standard PER-002-0 and (2) includes requirements pertaining to personnel credentials for reliability coordinators similar to those in PER-003-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1417 Sen 3 Item 2	4/29/2011
S- Ref 10338 - With regard to APPAs comments, consistent with our discussion above regarding Measures and Levels of Non-Compliance, we leave it to the discretion of the ERO whether it is necessary that each Requirement of this Reliability Standard have a corresponding Measure.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1416 Sen 1	4/29/2011
S- Ref 10339 - …direct the ERO to clarify the term "corrective action" consistent with this discussion when it modifies PRC-001-1 in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1441	9/2/2016
S- Ref 10340 - …direct the ERO to consider FirstEnergy and California PUC's comments about the maximum time for corrective action in the ERO Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1444	9/2/2016
S- Ref 10341 - Upon detection of failures in relays or protection system elements on the bulk power system that threaten reliability, relevant transmission operators must be informed promptly, but within a specified period of time. A requirement that transmission and generator operators be informed immediately upon the detection of failures in relays or protection system elements on the Bulk-Power System that would threaten reliable operation, so that these entities could carry out appropriate corrective control actions consistent with those used in mitigating IROL violations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1445 (See also Para 1420-1445)	9/2/2016

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10342 - ...direct the ERO, in the Reliability Standards development process, to determine the appropriate amount of time after the detection of relay failures, in which relevant transmission operators must be informed of such failures.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1445	9/2/2016
S- Ref 10343 - Once informed, transmission operators must carry out corrective control actions that return the system to a stable state that respects system requirements as soon as possible and no longer than 30 minutes.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1449	9/2/2016
S- Ref 10344 - We agree with APPA that the added Measures and Levels of Non-Compliance incorrectly reference non-existent requirements. We direct the ERO to revise the references accordingly.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1446	9/2/2016
S- Ref 10345 - …direct the ERO to consider APPA, Alcoa and Otter Tail's suggestions in the Reliability Standards development process as it modifies PRC-002-1 to provide missing information needed for the Commission to act on this Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1456	12/15/2014
S- Ref 10346 - …direct the ERO to consider APPA's suggestions in the Reliability Standards development process as it modifies PRC-003-1 to provide missing information needed for the Commission to act on this Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1461	9/15/2014
S- Ref 10347 - WECC will address the shortcomings identified by NERC in developing a permanent, replacement regional Reliability Standard.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 78	2/9/2009
S- Ref 10348 - The Commission agrees with the shortcomings identified by NERC regarding WECC-PRC-STD-003-1 and expects WECC in developing a permanent, replacement standard to address these shortcomings as it has committed to do.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 89	2/9/2009

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10349 - Consider ISO-NEs suggestion that LSEs and transmission operators should be listed as applicable entities.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1469	9/15/2014
S- Ref 10350 - The Regional Entity should develop procedures for corrective action plans.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1469	9/9/2010
S- Ref 10351 - …direct the ERO to develop a modification to PRC-005-1 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1475	2/26/2013
S- Ref 10352 - …direct the ERO to consider FirstEnergy's and ISO-NE's suggestion to combine PRC-005-1, PRC-008-0, PRC-011-0 and PRC-017-0 into a single Reliability Standard through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1475	2/26/2013
S- Ref 10353 - The Commission expects that this function will pass from the regional reliability organization to the Regional Entity after they are approved.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1480	3/31/2011
S- Ref 10354 - The Commission agrees with NERCs concerns regarding the format and content of WECC-PRC-STD-005-1 and expects WECC, in developing a permanent, replacement standard, to address these concerns, including but not limited to inclusion of all relevant documents.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 98	2/9/2009

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10355 - …direct the ERO to develop a modification to PRC-008-0 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1492	2/26/2013
S- Ref 10356 - …direct the ERO to develop a modification to PRC-010-0 through the Reliability Standards development process that requires that an integrated and coordinated approach be included in all protection systems on the Bulk-Power System, including generators and transmission lines, generators' low voltage ride-through capabilities, and UFLS and UVLS programs.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1509	12/15/2014
S- Ref 10358 - …direct the ERO to submit a modification to PRC-011-0 through the Reliability Standards development process that includes a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1516	2/26/2013
S- Ref 10359 - Consider APPAs suggestions for interconnection-wide consistency in the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1520	3/5/2013
S- Ref 10360 - Consider APPAs suggestions for interconnection-wide consistency in the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1524	2/25/2014
S- Ref 10361 - Consider APPAs suggestions for interconnection-wide consistency in the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1528	3/5/2013

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S- Ref 10362 - ... direct the ERO to develop a modification to PRC-017-0 through the Reliability Standards development process, that includes: (1) a requirement that maintenance and testing of a protection system must be carried out within a maximum allowable interval that is appropriate for the type of the protection system…	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1546	2/26/2013
S- Ref 10363 - …direct the ERO to develop a modification to PRC-017-0 through the Reliability Standards development process, that includes: … (2) a requirement that documentation identified in Requirement R2 shall be routinely provided to the ERO or Regional Entity.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1546	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10364 - ...direct the ERO to consider FirstEnergy's suggestion in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1566	12/15/2014
S- Ref 10365 - ...direct the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1787	5/30/2013
S- Ref 10366 - Consider Santa Clara's comments on requirements R7.2 and R7.3 on transmission operator notification requirements as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1588	3/18/2015 First: 4/16/2013
S- Ref 10367 - ...directs the ERO to provide Measures and Level of Non-Compliance for this Requirement	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1580	3/18/2015 First: 4/16/2013

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S- Ref 10368 - The definition of "emergency" could be further clarified. We discuss this issue in this Final Rule in connection with Reliability Standard EOP-001-0 and conclude that emergency states need to be defined and that criteria for entering these states and authority for declaring them need to be specified.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1585	3/18/2015 First: 4/16/2013
S- Ref 10369 - …direct the ERO to modify Reliability Standard TOP-002-2 to require the next-day analysis for all IROLs to identify and communicate control actions to system operators that can be implemented within 30 minutes following a contingency to return the system to a reliable operating state and prevent cascading outages.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1601 Sen 8	3/18/2015 First: 4/16/2013
S- Ref 10370 - Requires next-day analysis of minimum voltages at nuclear power plants auxiliary power buses.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1603; Para 1598	3/18/2015 First: 4/16/2013
S- Ref 10371 - Requires simulation contingencies to match what will actually happen in the field.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1608 Sen 4 Item 4	3/18/2015 First: 4/16/2013
S- Ref 10372 - Consider the comments of ISO-NE and the NRC with respect to requirement R12 and measure M7 as part of the standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1607; Para 1597	3/18/2015 First: 4/16/2013
S- Ref 10373 - Address critical energy infrastructure confidentiality as part of the routine standard development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1600	3/18/2015 First: 4/16/2013
S- Ref 10374 - Inform the nuclear plant operator in real-time if the auxiliary power bus voltages cannot be maintained.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1603	3/18/2015 First: 4/16/2013

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S- Ref 10375 - Commenters did not take issue with the proposed interpretation of the term deliverability as the ability to deliver the output from generation resources to firm load without any reliability criteria violations for plausible generation dispatches. The Commission adopts this proposed interpretation. In order to ensure the necessary clarity, the term as used in Requirement R7 of TOP-002-2 should be understood in this manner.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1606	3/18/2015 First: 4/16/2013
S- Ref 10376 - …directs the ERO to develop a modification to TOP-003-0 that requires the communication of scheduled outages to all affected entities well in advance to ensure reliability and accuracy of ATC calculations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1620	3/18/2015 First: 4/16/2013
S- Ref 10377 - ...direct the ERO to modify the Reliability Standard to incorporate an appropriate lead time for planned outages.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1621	3/18/2015 First: 4/16/2013
S- Ref 10378 - Consider TVAs suggestion for including breaker outages within the meaning of facilities that are subject to advance notice for planned outages.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1622	3/18/2015 First: 4/16/2013
S- Ref 10379 - …direct the ERO to modify the Reliability Standard to require that any facility below the thresholds that, in the opinion of the transmission operator, balancing authority, or reliability coordinator will have a direct impact on the reliability of the Bulk-Power System be subject to Requirement R1 for planned outage coordination.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1624	3/18/2015 First: 4/16/2013
S- Ref 10380 - …direct that the ERO develop a modification to Requirement R4 providing that the system should be restored to respect proven reliable power system limits as soon as possible and in no longer than 30 minutes.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1636	3/18/2015 First: 4/16/2013

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10381 - …direct the ERO to develop a modification to the Reliability Standard that explicitly incorporates this interpretation with the details identified in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1638	3/18/2015 First: 4/16/2013
S- Ref 10382 - ...direct the ERO to consider Santa Clara's suggestion regarding changes to Requirement R2 in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1639	3/18/2015 First: 4/16/2013
S- Ref 10383 - …direct the ERO to conduct a survey on the operating practices and actual experiences surrounding drifting in and out of IROL violations.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1637	3/18/2015 First: 4/16/2013 and Oct 2008
S- Ref 10384 - ...direct the ERO to develop a modification to TOP-005-1 through the Reliability Standards development process regarding the operational status of special protection systems and power system stabilizers in Attachment 1.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1648	3/18/2015 First: 4/16/2013
S- Ref 10386 - Consider FirstEnergy's modifications to Attachment 1 and ISO-NEs recommended revision to requirement R4 in the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1650	3/18/2015 First: 4/16/2013
S- Ref 10387 - Add requirement related to the provision of minimum capabilities that are necessary to enable operators to deal with real-time situations and to ensure reliable operation of the bulk power system.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1660	5/26/2016
S- Ref 10388 - Clarify the meaning of appropriate technical information concerning protective relays.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1663; Para 1665	3/18/2015 First: 4/16/2013

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S- Ref 10389 - The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1664	3/18/2015 First: 4/16/2013
S- Ref 10391 - …direct the ERO to consider NRC's comments in the Reliability Standards development process when addressing TOP-007-0 as part of its Work Plan.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1673	3/18/2015 First: 4/16/2013
S- Ref 10392 - The ERO should consider APPA's comment regarding the missing Measures in the ERO's Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1681	3/18/2015 First: 4/16/2013
S- Ref 10393 - ...direct the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1692	10/19/2011
S- Ref 10394 - Consider the full range of variables when determining critical system conditions but only those deemed to be significant need to be assessed and documentation provided that explain the rational for selection.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1706	10/19/2011
S- Ref 10395 - System performance should be assessed based on contingencies that mimic what happens in real-time.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1716	10/19/2011
S- Ref 10396 - Consider appropriate revisions to the reliability standards to deal with cyber security events.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1719	10/19/2011
S- Ref 10397 - With regard to SDG&Es suggestion to clarify specific elements of this Reliability Standard, we direct the ERO to consider such suggestions in its Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1727	10/19/2011

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10398 - ...direct the ERO to include these modifications to the Reliability Standard through its Reliability Standards development process to provide for the appropriate sharing of information with neighboring systems.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1755	10/19/2011
S- Ref 10399 - ...direct the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1725	10/19/2011
S- Ref 10400 - Submit an informational filing, in addition to regional criteria, all utility and RTO/ISO differences in transmission planning criteria that are more stringent than those specified by the TPL standards.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1693	10/19/2011
S- Ref 10401 - …direct NERC to submit a filing within 30 days of the date of this order explaining whether Requirement WR1.b is consistent with the second interpretation of IRO-005-1 (two contingencies away from cascading failure).	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 108	7/9/2007
S- Ref 10402 - that WECC in developing a permanent, replacement regional Reliability Standard: (1) clarify any inconsistency between the Requirement WR1.b and corresponding Measure WM1; and (2) ensure that the requirements currently set forth in Measures WM1 are set forth in the Requirements and that corresponding Measures simply quantify the frequency, duration and magnitude of the violations as determined by the Requirements.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 109	7/9/2007
S- Ref 10403 - ...expect that WECC will address the shortcomings identified by NERC in developing a permanent, replacement regional Reliability Standard.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 110	2/9/2009

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S- Ref 10404 - Consider the full range of variables when determining critical system conditions but only those deemed to be significant need to be assessed and documentation provided that explain the rational for selection.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1765	10/19/2011
S- Ref 10405 - ...direct the ERO to modify TPL-001-0 to require a peer review of planning assessments with neighboring entities.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1766	10/19/2011
S- Ref 10406 - ...directs the ERO to modify Requirement R1.3 of TPL-001-0 to substitute the reference to the regional reliability organization with a reference to the Regional Entity.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1767	10/19/2011
S- Ref 10407 - ...directs a modification to this Reliability Standard to require assessments of outages of critical long lead time equipment, consistent with the entity's spare equipment strategy.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1768	10/19/2011
S- Ref 10408 - ...directs the ERO to modify the Reliability Standard to address the concerns regarding footnote (a) of Table 1, including the applicability of emergency ratings and consistency of normal ratings and voltages with values obtained from other Reliability Standards.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1769	10/19/2011
S- Ref 10409 - …directs the ERO to modify TPL-002-0 to require that critical system conditions and study years be determined in the same manner as it directed with regard to TPL-001-0.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1785	10/19/2011
S- Ref 10410 - …directs the ERO to modify the Reliability Standard to require assessments of planned outages of long lead time critical equipment consistent with the entity's spare equipment strategy.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1786	10/19/2011

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S- Ref 10411 - ...directs the ERO to modify the Reliability Standard to explicitly require either that all generators are capable of riding through the same set of Category B and C contingencies, as required by wind generators in Order No. 661, or that those generators that cannot ride through be simulated as tripping.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1787	10/19/2011
S- Ref 10412 - ... directs the ERO to modify the Reliability Standard to require documentation of load models used in system studies and the supporting rationale for their use.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1789	10/19/2011
S- Ref 10413 - ...directs the ERO to modify the standard to clarify the phrase of footnote (a) that states “permit operating steps necessary to maintain system control” to clarify the use of emergency ratings.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1790	10/19/2011
S- Ref 10414 - Consider NRCs comments regarding clarifying the N-1 state as being always applicable to the current conditions as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1788	10/19/2011
S- Ref 10415 - Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The Commission directs the ERO to clarify the Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1794 Sen 1 and 2	3/31/2011 (FERC proposed remand)
S- Ref 10416 - ...consider developing a ceiling on the amount and duration of consequential load loss that will be acceptable.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1795 Sen 5 and 6	3/31/2011 (FERC proposed remand)

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10417 - Regarding the comments of Entergy and Northern Indiana that the Reliability Standard should allow entities to plan for the loss of firm service for a single contingency, the Commission finds that their comments may be considered through the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1794 Sen 3	3/31/2011 (FERC proposed remand)
S- Ref 10418 - …directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1796 Sen 9	3/31/2011
S- Ref 10419 - ...direct the ERO to modify TPL-003-0 to require that critical system conditions and study years be determined in the same manner as we directed with regard to TPL-001-0, for the reasons as set forth in our discussion of TPL-001-0 (see Ref 10409).	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1817	10/19/2011
S- Ref 10420 - …direct the ERO to modify footnote (c) of Table 1 to the Reliability Standard to clarify the term “controlled load interruption.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1818	10/19/2011
S- Ref 10421 - ...direct the ERO to modify the Reliability Standard to require definition and documentation of proxies necessary to simulate cascading outages.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1820	10/19/2011
S- Ref 10422 - Tailor the purpose statement to reflect the specific goal of the standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1821	10/19/2011
S- Ref 10423 - Address NRC concerns as described in TPL-002 through the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1822	10/19/2011

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10424 - Consider the comments on major load pockets as part of the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1824 Sen 8	10/19/2011
S- Ref 10425 - ...direct the ERO to modify TPL-004-0 to require that critical system conditions and study years be determined in the same manner as we directed with regard to TPL-001-0 and for the reasons stated there.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1832	10/19/2011
S- Ref 10426 - MidAmerican states that it supports the proposal to modify TPL-004-0 to require identification of options for reducing the probability or impacts of extreme events that cause cascading. Accordingly, for the reasons cited in the NOPR, the Commission directs the ERO to modify the Reliability Standard to make this modification to the Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1833	10/19/2011
S- Ref 10427 - ...direct the ERO to expand the list of events with examples of such events identified above.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1834	10/19/2011
S- Ref 10428 - The Commission received no comments on its proposal to modify the purpose statement of TPL-004-0 to reflect the specific goal of the Reliability Standard. The Commission directs that this modification be made.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1835	10/19/2011
S- Ref 10429 - Encourages NERC to utilize input from the Commissions technical conferences on regional planning as directed in Order No. 890 to improve this standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1841	10/19/2011
S- Ref 10430 - ...modify VAR-001-1 to include reliability coordinators as applicable entities and include a new requirement(s) that identifies the reliability coordinator's monitoring responsibilities.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1855	3/18/2015
S- Ref 10431 - ... direct the ERO to address the reactive power requirements for LSEs on a comparable basis with purchasing-selling entities.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1858	9/9/2010

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10432 - Include APPAs comments regarding varying power factor requirements due to system conditions and equipment in the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1862	6/9/2014
S- Ref 10433 - …the NOPR proposed directing the ERO to modify VAR-001-1 to include more detailed and definitive requirements on "established limits" and "sufficient reactive resources" and identify acceptable margins (i.e. voltage and/or reactive power margins) above voltage instability points to prevent voltage instability and to ensure reliable operations. We will keep this direction, and direct the ERO to include this modification in this Reliability Standard.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1868	6/9/2014
S- Ref 10434 - We recognize that our proposed modification does not identify what definitive requirements the Reliability Standard should use for established limits and sufficient reactive resources. Rather, the ERO should develop appropriate requirements that address the Commission's concerns through the ERO Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1869	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10436 - Address the concerns of Dynegy, EEI, and MISO through the standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1869	6/9/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10437 - direct the ERO, through its Reliability Standards development process, to modify Reliability Standard VAR-001-1 to include Requirements to perform voltage stability analysis periodically, using online techniques where commercially-available, and offline simulation tools where online tools are not available, to assist real-time operations. The ERO should consider the available technologies and software as it develops this modification to VAR-001-1 and identify a process to assure that the Reliability Standard is not limiting the application of validated software or other tools.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1875	5/26/2016
S- Ref 10438 - …expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1879	9/9/2010
S- Ref 10439 - ...expect the ERO to consider the comments of SoCal Edison with regard to reliability and SMA in its process for developing the technical capability requirements for using controllable load as a reactive resource in the applicable Reliability Standards.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1879	9/9/2010
S- Ref 10440 - ...direct the ERO to include APPA's concern in the Reliability Standards development process.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1862	6/9/2014
S- Ref 10441 - direct the ERO to develop appropriate modifications to this Reliability Standard to address the power factor range at the interface between LSEs and the Bulk-Power System.	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	Order No. 788 RM13-8-000	Para 1861 (See also 1863)	2013 N/A - Withdrawn by FERC Order No. 788

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S- Ref 10442 - Consider Dynegy's suggestion to improve the standard. Dynegy believes that VAR-002-1 should be modified to require more detailed and definitive requirements when defining the time frame associated with an incident of non-compliance (i.e. each 4-second scan, 10-minute integrated value, hourly integrated value).	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 1885	6/9/2014
S- Ref 10443 - ...expect that WECC, in developing a permanent, replacement standard, will address the shortcomings identified by NERC regarding WECC-VAR-STD-002a-1 including to address identified format-related shortcomings.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 117	2/9/2009
S- Ref 10444 - ...expect WECC to address the shortcomings identified by NERC when developing a permanent, replacement standard .... including to address identified format-related shortcomings.	Order Approving Regional Reliability Standards for WECC - Docket No. RR07-11	6/8/2007	119 FERC ¶ 61,260	RR07-11-000	Para 123	2/9/2009
S- Ref 10445 - ...directed to develop a timetable for development of the modifications to the CIP Reliability Standards and, if warranted, to develop and file with the Commission for approval, a second implementation plan.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 013	7/8/2009
S- Ref 10447 - ...direct the ERO to develop modifications to the CIP Reliability Standards that require a responsible entity to implement plans, policies and procedure that it must develop pursuant to the CIP Reliability Standards.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 075	5/22/2009
S- Ref 10448 - ...direct the ERO, in its development of a work plan, to consider developing modifications to CIP-002-1 and the provisions regarding technical feasibility exceptions as a first priority, before developing other modifications required by the Final Rule.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 090	5/22/2009
S- Ref 10449 - ...direct the ERO to include approval of the mitigation and remediation steps by the senior manager (identified pursuant to CIP-003-1) in the course of developing this framework of accountability.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 211	5/22/2009

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10452 - The Commission leaves to the EROs discretion whether to incorporate guidance on the development of a risk-based assessment methodology to identify critical assets into the CIP Reliability Standard, develop it as a separate guidance document, or some combination of the two.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 253 (See also 238)	5/22/2009
S- Ref 10453 -...direct the ERO to consider commenter concerns such as how to assess whether a generator or a blackstart unit is critical to Bulk-Power System reliability, the proper quantification of risk and frequency, facilities that are relied on to operate or shut down nuclear generating stations, and the consequences of asset failure and asset misuse by an adversary.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 254	5/22/2009
S- Ref 10454 - ...direct either the ERO or its designees to provide reasonable technical support to assist entities in determining whether their assets are critical to the Bulk-Power System.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 255	2/10/2011
S- Ref 10456 - ...direct the ERO to consider this clarification [the meaning of the phrase used for initial system restoration, in CIP-002-1, Requirement R1.2.4] in its Reliability Standards development process.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 257 (See also 250)	5/22/2009
S- Ref 10457 - The ERO should consider the issue of a Design-Basis Threat (DBT) profile of potential adversaries as an alternative approach to critical asset identification.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 258 and 252	1/31/2013
S- Ref 10458 - The ERO should consider Northern California's suggestion that the ERO establish a process for informal, case-by-case consultations with responsible entities that need assistance in complying with CIP-002-1 (in developing policies and procedures).	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 258 and 249	1/31/2013

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10459 - ...direct the ERO to specifically require the consideration of misuse of control centers and control systems in the determination of critical assets.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 282 (See also 279 - 281) (See also Sept 2004 NOPR on CIP version 4 Para 54 - 58)	5/22/2009
S- Ref 10462 - The ERO should consider modifying CIP-002-1 to allow an entity to rely upon the assessment of another entity with interest in the matter.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 321	1/31/2013
S- Ref 10467 - ...direct the ERO, in developing the accountability structure for the technical feasibility exception, to include appropriate provisions to assure that governmental entities can safeguard sensitive information.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 333	5/22/2009
S- Ref 10468 - ...direct the ERO to provide additional guidance for the topics and processes that the required cyber security policy should address in the cyber security policy required pursuant to CIP-003-1.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 355 (Related Para 356)	1/31/2013
S- Ref 10474 - ...direct the ERO to develop modifications to Requirement R6 of CIP-003-1 to provide an express acknowledgment of the need for the change control and configuration management process to consider accidental consequences and malicious actions along with intentional changes.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 397 and 398	1/31/2013
S- Ref 10481 - ...direct the ERO to identify the parameters of such exceptional circumstances through the Reliability Standards development process.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 443	5/22/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10483 - The ERO should consider the comments of APPA/LPPC (seeking clarification regarding discretion in reviewing results of personnel risk assessments and in coming to conclusions regarding the subject employees) and SDG&E (seeking refinements on various issues, including an industry-wide protocol for periodic background and criminal checks, and the use of pre-employment background check procedures for current employees) when developing modifications to CIP-004-1.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 446 (See also 441 and 442)	1/31/2013
S- Ref 10492 - The Commission adopts the CIP NOPRs proposal to direct the ERO to develop a requirement that each responsible entity must implement a defensive security approach including two or more defensive measures in a defense in depth posture when constructing an electronic security perimeter.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 496 (See also 503)	1/31/2013
S- Ref 10493 -...directs that a responsible entity must implement two or more distinct security measures when constructing an electronic security perimeter, the specific requirements should be developed in the Reliability Standards development process.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 502	1/31/2013
S- Ref 10513 - ...direct the ERO to modify Requirement R4 to require these representative active vulnerability assessments at least once every three years, with subsequent annual paper assessments in the intervening years.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 547	1/31/2013
S- Ref 10514 - ...direct the ERO to modify this CIP Reliability Standard to state that a responsible entity must, at a minimum, implement two or more different security procedures when establishing a physical security perimeter around critical cyber assets.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 572	1/31/2013

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10515 - ...direct the ERO to consider, based on the content of the modified CIP-006-1, whether further guidance on defense in depth (a responsible entity must implement two or more distinct and complimentary physical access controls at a physical access point of the perimeter) should be developed in a reference document outside of the Reliability Standards.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 575	5/22/2009
S- Ref 10536 - ...direct the ERO to provide more direction on what features, functionality, and vulnerabilities the responsible entities should address when conducting the vulnerability assessments.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 643	1/31/2013
S- Ref 10553 - ...direct the ERO to modify CIP-009-1 to incorporate use of good forensic data collection practices and procedures into this CIP Reliability Standard.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 706	1/31/2013
S- Ref 10554 - ...direct the ERO to revise CIP-009-1 to require data collection, as provided in the Blackout Report.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 710 (See also 706)	1/31/2013
S- Ref 10555 - The Commission adopts, with modifications, the CIP NOPR proposal to develop modifications to CIP-009-1 through the Reliability Standards development process to require an operational exercise once every three years (unless an actual incident occurs, in which case it may suffice), but to permit reliance on table-top exercises annually in other years.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 725	1/31/2013
S- Ref 10560 - ...direct the ERO to submit a work plan for Commission approval for developing and filing for approval the modifications to the CIP Reliability Standards that we are directing in this Final Rule	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 089	5/22/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10561 - ...direct the ERO to require more frequent, semiannual, self-certifications prior to the date by which full compliance is required	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 096	5/22/2009
S- Ref 10564 - ...direct the ERO to develop modifications to the CIP Reliability Standards that do not include this term. We note that many commenters, including NERC, agree that the reasonable business judgment language should be removed.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 128 (See also 106 - 138)	5/22/2009
S- Ref 10566 - ...direct the ERO to remove acceptance of risk language from the CIP Reliability Standards.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 150 (See also 151 - 156)	5/22/2009
S- Ref 10568 - ...direct the ERO to develop a set of conditions or criteria that a responsible entity must follow when relying on the technical feasibility exception contained in specific Requirements of the CIP Reliability Standards	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 178 (See also 179 - 186)	5/22/2009
S- Ref 10570 - ...direct the ERO to develop a requirement that the responsible entity must develop, document and implement a mitigation plan that achieves a comparable level of security to the Requirement.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 192	5/22/2009
S- Ref 10571 - The Commission thus adopts its CIP NOPR proposal that use and implementation of technical feasibility exceptions must be governed by a clear set of criteria.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 209	5/22/2009
S- Ref 10572 - ...direct the ERO to design and conduct an approval process through the Regional Entities and the compliance audit process.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 218	5/22/2009

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10573 - ...direct NERC, in developing the accountability structure for the technical feasibility exception, to include appropriate provisions to assure that governmental entities that are subject to Reliability Standards as users, owners or operators of the Bulk-Power System can safeguard sensitive information.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 219	5/22/2009
S- Ref 10574 - ...directs the ERO to submit an annual report to the Commission that provides a wide-area analysis regarding use of the technical feasibility exception and the effect on Bulk-Power System reliability.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 220	9/28/2011
S- Ref 10575 - ...directs the ERO to control and protect the data analysis to the extent necessary to ensure that sensitive information is not jeopardized by the act of submitting the report to the Commission.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 221	5/22/2009
S- Ref 10576 - ...directs the ERO to develop a set of criteria to provide accountability when a responsible entity relies on the technical feasibility exceptions in specific Requirements of the CIP Reliability Standards.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 222	5/22/2009
S- Ref 10577 - ...directs the ERO, in developing the guidance discussed above regarding the identification of critical assets, to consider the designation of various types of data as a critical asset or critical cyber asset.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 272	1/31/2013
S- Ref 10578 - … directs the ERO to develop guidance on the steps that would be required to apply the CIP Reliability Standards to such data and to consider whether this also covers the computer systems that produce the data.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 272	1/31/2013
S- Ref 10579 - ...directs the ERO to develop, pursuant to its Reliability Standards development process, a modification to CIP-002-1 to explicitly require that a senior manager annually review and approve the risk-based assessment methodology.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 294 (See also 296 - 291)	5/22/2009

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10580 - The Commission adopts its CIP NOPR interpretation that Requirement R2 of CIP-003-1 requires the designation of a single manager who has direct and comprehensive responsibility and accountability for implementation and ongoing compliance with the CIP Reliability Standards. The Commissions intent is to ensure that there is a clear line of authority and that cyber security functions are given the prominence they deserve.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 381 (See also 379)	5/22/2009
S- Ref 10581 - ...direct the ERO to provide guidance, regarding the issues and concerns that a mutual distrust posture must address in order to protect a responsible entity's control system from the outside world.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 412 (See also 408 - 410) (See also footnote 24 found in Para 24)	1/31/2013
S- Ref 10582 - ...direct the ERO to develop a modification to CIP-004-1 that would require affected personnel to receive required training before obtaining access to critical cyber assets	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 431	5/22/2009
S- Ref 10583 - ...direct the ERO to treat any alternative measures for Requirement R1.1 of CIP-006-1 as a technical feasibility exception to Requirement R1.1, subject to the conditions on technical feasibility exceptions.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 560	5/22/2009
S- Ref 10584 - …directs the ERO to eliminate the acceptance of risk language from Requirements R2.3 and R3.2.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 597	5/22/2009

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10585 - …directs the ERO to revise Requirement R3 to remove the acceptance of risk language and to impose the same conditions and reporting requirements as imposed elsewhere in the Final Rule regarding technical feasibility.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 600	5/22/2009
S- Ref 10586 - ...directs the ERO to eliminate the acceptance of risk language from Requirement R4.2, and also attach the same documentation and reporting requirements to the use of technical feasibility in Requirement R4, pertaining to malicious software prevention, as elsewhere	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 622 Sen 1 (See also 614 and 619)	12/29/2009
S- Ref 10587 - ...direct the ERO to revise Requirement R9 to state that the changes resulting from modifications to the system or controls shall be documented quicker than 90 calendar days.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 651	5/22/2009
S- Ref 10588 - Therefore, we will not allow NERC to reconsider the Violation Risk Factor designations in this instance but, rather, direct below that NERC make specific modifications to its designations.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 757	5/22/2009
S- Ref 10589 - ...directs NERC to submit a complete Violation Risk Factor matrix encompassing each Commission approved CIP Reliability Standard.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 759	5/22/2009
S- Ref 10590 - The Commission adopts the CIP NOPR proposal to direct the ERO to revise 43 Violation Risk Factors.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 767	5/22/2009
S- Ref 10591 - ...direct the ERO to consider allowing for the 30 minute system adjustment period, the system must be capable of withstanding an N-1 contingency, with load shedding available to system operators as a measure of last resort to prevent cascading failures.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 53	6/30/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10592 - However, the Commission concludes that nine filed Violation Risk Factors for FAC Reliability Standards Requirements are not consistent with these guidelines and also concludes that one Requirement where no Violation Risk Factor was filed should have been assigned a Violation Risk Factor consistent with an identically worded Requirement from another FAC Reliability Standard. Thus, the Commission directs NERC to modify these ten Violation Risk Factors.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 135	6/30/2008
S- Ref 10593 - ...NERC must submit a compliance filing with the revised Violation Risk Factors no later than 90 days before the effective date of the relevant Reliability Standard.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 136	6/30/2008
S- Ref 10594 - ...direct NERC to submit a complete Violation Risk Factor matrix encompassing each Commission-approved Reliability Standard and including the correct corresponding version number for each Requirement when it files revised Violation Risk Factors for the FAC Reliability Standards.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 138	6/30/2008
S- Ref 10595 - In revising the Violation Risk Factors, NERC must address the Commissions concerns, as outlined below, and also follow the five guidelines for evaluating the validity of each Violation Risk Factor assignment.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 138	6/30/2008
S- Ref 10596 - However, for the reasons explained below, we remand NERC's definition of "Cascading Outages" subject to NERC refiling.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 014	6/30/2008
S- Ref 10597 - ...direct WECC to file Violation Risk Factors for the FAC-010-1 and FAC-011-1 no later than the effective date of the applicable Reliability Standard.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 146	6/30/2008

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10598 - ...directs NERC to revise the Violation Risk Factor assigned to FAC-010-1, Requirements R2.1-R2.2 to high.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 165	6/30/2008
S- Ref 10599 - ...directs NERC to assign a high Violation Risk Factor to FAC-014-1, Requirement R5 and sub-Requirements R5.1.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 175	6/30/2008
S- Ref 10600 - ...directs NERC to ensure that the proposed Violation Risk Factor for FAC- 010-1, Requirement R3.6 is changed from low to medium.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 178	6/30/2008
S- Ref 10601 - direct that any revised TPL Reliability Standards must reflect consistency in the lists of contingencies between the two	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	Order No. 788 RM13-8-000	Para 49	2013 N/A - Withdrawn by FERC Order No. 788
S- Ref 10602 - ...direct NERC to revise the Reliability Standard through the Reliability Standards development process to address our concern. This could, for example, be accomplished by deleting the phrase, e.g., load greater than studied from sub-Requirement R.2.3.2.	Facilities Design, Connections and Maintenance Reliability Standards	12/27/2007	Order 705	RM07-3-000	Para 70	6/30/2008
S- Ref 10605 - ...direct NERC to include in its first performance assessment three years from the date of certification a report analyzing the length of time taken to develop a new or modified Reliability Standard from the submission of a SAR through approval of a Reliability Standard by the ERO board, as discussed herein.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para D	7/1/2009
S- Ref 10606 - Submit an additional compliance filing within 60 days of the issuance of this order, and a quarterly report on the balloting results of its Reliability Standards Development Process.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 1	3/19/2007

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10607 - ...direct the ERO to develop a work plan to propose a continuing improvement process to consider adequate level of reliability when developing new or modified Reliability Standards.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 16	3/19/2007
S- Ref 10608 - The ERO must address the issue of whether an adequate level of reliability can be defined to partly or wholly apply to all Reliability Standards, whether it can be defined for certain sets of Reliability Standards (BAL, FAC etc.), or whether, in some instances, it must be tailored to each individual Reliability Standard.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 16	3/19/2007
S- Ref 10609 - The ERO must consider opportunities to develop and apply metrics that can form the basis for broadly defining an adequate level of reliability, such as the creation of a precisely defined set of system operating states.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 16	3/19/2007
S- Ref 10610 - Report to us quarterly for the next three years its analysis of the voting results, including trends and patterns that may signal a need for improvement in the voting process, such as the balloting down of a Reliability Standard and subsequent ballot approval of a less stringent version of the Reliability Standard.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 18	3/19/2007
S- Ref 10611 - …direct that NERC revise the proposed expedited urgent action process to (1) provide for the expedited development of a Reliability Standard in extraordinary circumstances without the limitation on when it can be invoked by the Commission and (2) incorporate the ability to adjust the timeliness of the process to meet a Commission-imposed deadline and still allow for due process.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 28	3/19/2007

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10612 - ...direct to revise the emergency action process to make it clear that, when the Commission determines that extraordinary circumstances exist, NERC must invoke its emergency action process without NERC board discretion to overrule that determination.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 28	3/19/2007
S- Ref 10613 - ...direct NERC to modify both the regular and expedited Reliability Standard development procedures to explicitly provide for timely adherence to a Commission-imposed deadline.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 28	3/19/2007
S- Ref 10616 - ...direct NERC to revise its Reliability Standard development procedure to clearly indicate how it will initiate the development of a new or revised Reliability Standard in response to a Commission directive separate from the SAR process.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 29	3/19/2007
S- Ref 10618 - …direct the ERO to monitor the length of time taken to develop a new or modified Reliability Standard from the submission of a SAR through approval of a Reliability Standard by the ERO board.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 31	3/19/2007
S- Ref 10619 - ...submit a report as part of its performance assessment at the three year anniversary of the certification of the ERO that identifies how long each new Reliability Standard or modification under development has taken up to that point.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 31	7/1/2009
S- Ref 10620 - ...direct NERC to modify section 306 so that the compliance and certification committee is responsible for monitoring NERCs compliance regarding Reliability Standards development.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 63	3/19/2007

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10621 - direct that NERC modify its Rules of Procedure to provide that the ERO will comply with each Reliability Standard that identifies the ERO as an applicable entity, identify the component of NERC that will monitor NERCs compliance with such standards, and state that non-compliance would constitute a violation of NERCs Rules of Procedure and subject NERC to any consequences of such a violation.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 65	3/19/2007
S- Ref 10622 - direct NERC to develop the Violation Risk Factors through the procedure described in section 1400 of its Rules of Procedure.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para 91	3/19/2007
S- Ref 10624 - ...direct NERC to file with the Commission quarterly reports for the next three years, within 30 days of the end of each quarterly period, beginning with the first quarter of 2007, on voting results in the Reliability Standard development process, as discussed herein.	Order on Compliance Filing - Docket No. RR06-1-003	1/18/2007	118 FERC ¶61,030	RR06-1-003	Para C	3/19/2007
S- Ref 10625 - …direct NERC to submit a compliance filing to address the Commissions concerns with regard to the guidelines the Commission applied to each Requirement listed in Appendix B and to provide justification for NERCs Violation Risk Factor assignment. The Commission may change its determination based on the explanation provided in the compliance filing.	Order on Violation Risk Factors - Docket Nos. RR07-9 and RR07-10	5/18/2007	119 FERC ¶ 61,145	RR07-9-000; RR07-10-000	Para 43	6/4/2007 8/17/2007
S- Ref 10626 - In addition to those approved Reliability Standards identified by NERC where Requirements, by omission, were not assigned a Violation Risk Factor, the Commission has also identified others. Requirements for Reliability Standards MOD-016-1, R2, R2.1, R3, and R3.1 were not assigned Violation Risk Factors. The Commission directs NERC to submit these Violation Risk Factor assignments in its compliance filing	Order on Violation Risk Factors - Docket Nos. RR07-9 and RR07-10	5/18/2007	119 FERC ¶ 61,145	RR07-9-000; RR07-10-000	Para 44	8/16/2007

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S- Ref 10627 - The Commissions review has also found several instances where Violation Risk Factors were inappropriately assigned. For example, our review found instances where Violation Risk Factors were assigned to explanatory statements, phrases and/or text. We direct NERC to remove Violation Risk Factor assignments in these instances in the compliance filing required in 15 days.	Order on Violation Risk Factors - Docket Nos. RR07-9 and RR07-10	5/18/2007	119 FERC ¶ 61,145	RR07-9-000; RR07-10-000	Para 45	8/17/2007
S- Ref 10628 - ...direct NERC to submit a complete Violation Risk Factor matrix encompassing each Commission-approved Reliability Standard.	Order on Violation Risk Factors - Docket Nos. RR07-9 and RR07-10	5/18/2007	119 FERC ¶ 61,145	RR07-9-000; RR07-10-000	Para 46	8/17/2007
S- Ref 10629 - ...direct NERC to file modifications to 28 of the proposed Violation Risk Factors within 15 days. This, we are approving as modified the proposed Violation Risk Factors effective June 1, 2007. In addition, the Commission directs NERC to submit a compliance filing within 60 days of this order that explains the rationale for assigning certain risk factor levels in approximately 75 instances.	Order on Violation Risk Factors - Docket Nos. RR07-9 and RR07-10	5/18/2007	119 FERC ¶ 61,145	RR07-9-000; RR07-10-000	Para 2	8/17/2007
S- Ref 10630 - ...direct NERC to make a compliance filing within 30 days of the date of this order.	Order on Compliance Filing - Docket No. RR06-1-007	6/7/2007	119 FERC ¶ 61,248	RR06-1-007	Para 1	8/6/2007
S- Ref 10631 - ...direct NERC to develop violation severity levels for each requirement and subrequirement of each Reliability Standard, either through the Reliability Standards development process or through another expedited process, and submit them to the Commission.	Order on Compliance Filing - Docket No. RR06-1-007	6/7/2007	119 FERC ¶ 61,248	RR06-1-007	Para 80	3/3/2008
S- Ref 10632 - NERC shall submit a compliance filing as to the modifications and submissions required in this order within 60 days of the date of its issuance.	Order on Compliance Filing - Docket No. RR06-1-007	6/7/2007	119 FERC ¶ 61,248	RR06-1-007	Para B	8/6/2007
S- Ref 10633 - ...direct NERC to make a compliance filing within 30 days of the date of this order.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 1	12/17/2007

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10634 - ...direct NERC to revise the Violation Risk Factor assignment for BAL-001-0, Requirements R1 and R2 to medium.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 25	12/17/2007
S- Ref 10635 - ...direct NERC to revise the Violation Risk Factor for BAL-002-0, Requirement BAL-002-0, Requirement R2 to medium.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 29	12/17/2007
S- Ref 10636 - ...direct NERC to assign a Violation Risk Factor of medium to BAL-002-0, Requirement R4.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 30	12/17/2007
S- Ref 10637 - ...direct NERC to revise the Violation Risk Factor for BAL-004-0, Requirement R3 to medium.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 43	12/17/2007
S- Ref 10638 - ...direct NERC to revise the subject Violation Risk Factors to medium.[re: BAL-005-0 R1.1, 1.2, 1.3]	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 47	12/17/2007
S- Ref 10639 - ...direct NERC to revise the Violation Risk Factor assignment for BAL-005-0, Requirement R2 to high.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 51	12/17/2007
S- Ref 10640 - ...direct NERC to revise the subject Violation Risk Factor to medium.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 55	12/17/2007
S- Ref 10641 - ...direct NERC to revise the Violation Risk Factor for BAL-005-0, Requirement R17 to medium	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 58	12/17/2007
S- Ref 10642 - ...direct NERC to revise the Violation Risk Factors for FAC- 008-1, Requirements R1.1, R1.2, R1.2.1, and R1.2.2 to medium.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 62	12/17/2007
S- Ref 10643 - ...direct NERC to revise the subject Violation Risk Factor to medium.	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 65	12/17/2007

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10644 - ...direct NERC to submit, within 30 days, a compliance filing containing these modifications incorporated into a revised version of the complete Violation Risk Factor matrix encompassing each Commission-approved Reliability Standard	Order on Compliance Filing - Docket Nos. RR07-9 and RR07-10	11/16/2007	121 FERC ¶ 61,179	RR07-9-003; RR07-10-003	Para 66	12/17/2007
S- Ref 10645 - we would consider a second implementation plan for achieving compliance with the revised CIP Reliability Standards. Since these revised CIP Reliability Standards could cause additional critical assets to be identified through the external review process, the Commission expects that the second implementation plan would include the compliance timetable for newly identified critical assets.	Order Denying Rehearing and Granting Clarification	5/16/2008	Order 706-A	RM06-22-001	Para 55	2/10/2011
S- Ref 10646 - ...expect that when NERC develops a schedule for responsible entities to bring newly identified critical assets into compliance with Reliability Standards CIP-002-1 through CIP-009-1, this schedule would be at least as prompt as the schedule it proposed.	Order Denying Rehearing and Granting Clarification	5/16/2008	Order 706-A	RM06-22-001	Para 56	2/10/2011
S- Ref 10647 - ...directed to submit a report on its analysis with regard to Guideline 1 within six months of this order, as discussed in the body of this order.	Order on Violation Severity Levels - Docket No. RR08-4	6/19/2008	123 FERC ¶ 61,284	RR08-4-000	Para 1 (C)	12/19/2008
S- Ref 10648 - ...directed to submit a compliance filing within six months of this order, justifying or modifying the Violation Severity Levels with regard to Guideline 2a, as discussed in the body of this order.	Order on Violation Severity Levels - Docket No. RR08-4	6/19/2008	123 FERC ¶ 61,284 and referenced in Order 722	RR08-4-000	Para 1 (D)	12/19/2008
S- Ref 10649 - ...direct to submit a compliance filing within six months certifying that it has revised each of the Violation Severity Level Assignments for consistency with Guidelines 2b, 3 and 4, validating the assignments that meet Guidelines 2b, 3, and 4.	Order on Violation Severity Levels - Docket No. RR08-4	6/19/2008	123 FERC ¶ 61,284 and referenced in Order 722	RR08-4-000	Para 1 (E)	3/21/2011

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10650 - …direct to file the modified Violation Severity Levels as identified in the Appendix within 30 days of this order, as discussed in the body of this order.	Order on Violation Severity Levels - Docket No. RR08-4	6/19/2008	123 FERC ¶ 61,284	RR08-4-000	Para 1 (B)	12/19/2008
S- Ref 10651 - ...direct the ERO to modify Requirement 9.3.5 to clarify references to coping times and off-site for restoration to address the concerns raised in the comments through its Reliability Standards development process.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 107	8/14/2009
S- Ref 10652 - ...direct NERC to submit a timeline for developing and filing the modification as a compliance filing to be made within 30 days of the date of this Final Rule.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 107	8/14/2009
S- Ref 10653 - ...direct the ERO to revise the violation risk factor assignment for Requirement R2 from lower to medium no later than 90 days before the effective date of the Reliability Standard.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 156	8/14/2009
S- Ref 10654 - ...direct the ERO to revise the violation risk factor assignment for Requirements R4.2 and R4.3 from medium to high no later than 90 days before the effective date of the Reliability Standard.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 168	8/14/2009
S- Ref 10655 - ...direct the ERO to revise the violation risk factor assignment for Requirement R5 from medium to high no later than 90 days before the effective date of the Reliability Standard.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 173	8/14/2009
S- Ref 10656 - ...direct the ERO to revise the violation risk factor assignment for Requirements R7 and R8 from medium to high no later than 90 days before the effective date of the Reliability Standard.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 179	8/14/2009
S- Ref 10657 - ...direct the ERO to revise the violation risk factor assignment for Requirement R9 from lower to medium no later than 90 days before the effective date of the Reliability Standard.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 187	8/14/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10658 - ...directs the ERO, in enforcing NUC-001-1, to require that an integrated entity provides documentation of its arrangements, including appropriate procedures and protocols, ensuring that its business units perform the functions under NUC-001-1 that would otherwise be met by separate entities.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 73	8/14/2009
S- Ref 10659 - ...direct the ERO to assess whether the entity providing service over the lower voltage facilities is also subject to NUC-001-1 concerning Transmission Entities and Agreements on NPIRs.	Mandatory Reliability Standard for Nuclear Plant Interface Coordination	10/16/2008	Order 716	RM08-3-000	Para 88	8/14/2009
S- Ref 10660 - ...direct NERC to use both historical data as the Commission intended in the VSL Order and 2008 compliance data in its evaluation of assigned violation severity levels applying Guideline 1.	Order on Rehearing and Clarification - Docket Nos. RR08-4-002 and RR08-4-003	11/20/2008	125 FERC ¶ 61,212	RR08-4-001; RR08-4-002	Para 22	12/1/2010
S- Ref 10661 - ...identify and compare (i) each requirement and its current violation severity level assignment, (ii) the requirements pre-2008 historical data, and (iii) the requirements 2008 compliance data.	Order on Rehearing and Clarification - Docket Nos. RR08-4-002 and RR08-4-003	11/20/2008	125 FERC ¶ 61,212	RR08-4-001; RR08-4-002	Para 30	12/1/2010
S- Ref 10662 - ...direct the ERO to submit a filing containing revisions to four of them, within 60 days of the date of this order.	VRF Order on Compliance Filing - Docket Nos. RM06-22-002 and RM06-22-003	1/27/2009	126 FERC ¶ 61,065	RM06-22-002; RM06-22-003	Para 14	6/30/2009
S- Ref 10663 - ...direct the ERO to engage in a stakeholder process to develop a more appropriate timeframe for nuclear power plants full compliance with CIP Reliability Standards.	Mandatory Reliability Standards for Critical Infrastructure Protection	3/19/2009	Order 706-B	RM06-22-000	Para 60	9/15/2009
S- Ref 10664 - ...direct the ERO to submit violation severity levels for all requirements and sub-requirements at issue in this proceeding within 30 days from the effective date of this final rule, as discussed below and as indicated in Attachment A.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 46	5/29/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10665 - ...direct the ERO to remove violation severity level assignments for Requirements R2 and R2.6 of FAC-010-2 and Requirement R2 of FAC-011-2.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 50	5/29/2009
S- Ref 10666 - ...direct the ERO to review those requirements for consistency with Violation Severity Level Order Guidelines 2b, 3, and 4 and submit the results of its review the earlier of six months of the effective date of the final rule or in its Violation Severity Order Guideline 2b, 3, and 4 compliance filing due in September 2009, whichever is earlier.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 52	3/21/2011
S- Ref 10667 - ...direct the ERO to review the violation severity levels assigned to Requirement R4 for consistency with Violation Severity Level Order Guidelines 2b, 3, and 4 within six months of the effective date of the final rule or in its Violation Severity Level Order Guideline 2b, 3, and 4 compliance filing, whichever is earlier.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 64	3/21/2011
S- Ref 10668 - ...direct the ERO to assign binary violation severity levels to each sub-requirement. Sub-requirements R4.1 through R4.3 are binary requirements and should be assigned a single violation severity level.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 65	5/29/2009
S- Ref 10669 - ...directs the ERO to modify Requirement R3 of FAC-011-2 to assign a Severe violation severity level to Requirement R3 of FAC-011-2 where the reliability coordinator is missing a description of four or more sub-requirements, within the range of R3.1 through R3.7, from its methodology for determining system operating limits.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 70	5/29/2009
S- Ref 10670 - ...directs the ERO to file revised violation severity levels for FAC-011-2, Requirement R3 within 30 days of the issuance of this final rule, as discussed above and as indicated in Attachment A.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 71	5/29/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10671 - ...directs the ERO to review the violation severity levels assigned to Requirement R4 for consistency with Violation Severity Level Order Guidelines 2b, 3, and 4 and submit the results of the review either within six months of the effective date of the final rule or in its Violation Severity Level Order Guideline 2b, 3, and 4 compliance filing, whichever is earlier.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 74	5/29/2009
S- Ref 10672 - direct the ERO to assign binary violation severity levels to each sub-requirement. Sub-requirements R4.1 through R4.3 are binary requirements and should be assigned a single violation severity level.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 75	5/29/2009
S- Ref 10673 - ...directs the ERO to review the violation severity levels assigned to the subject requirements for consistency with Violation Severity Level Order Guidelines 2b, 3, and 4 and submit the results of its review either within six months of the effective date of the final rule or in its Violation Severity Level Order Guideline 2b, 3, and 4 compliance filing, whichever is earlier	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 81	3/21/2011
S- Ref 10674 - ...directs the ERO to review the violation severity levels assigned to Requirement R4 for consistency with Violation Severity Level Order Guidelines 2b, 3, and 4 and submit the results of its review either within six months of the effective date of the final rule or in its Violation Severity Level Order Guideline 2b, 3, and 4 compliance filing, whichever is earlier.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 84	3/21/2011
S- Ref 10675 - ...directs the ERO to assign binary violation severity levels to Requirement R6 and sub-requirements R6.1 and R6.2.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 89	5/29/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10676 - The Commission agrees with BPAs comment relevant to designating the Regional Differences section of FAC-011-2 as section E and directs the ERO to file this revision within 30 days of the effective date of this final rule.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 98	5/29/2009
S- Ref 10677 - ...directs WECC to apply the violation risk factors approved for FAC-010-1 Requirements R2.4 and R2.5 and FAC-011-1 Requirement R3.3 to the WECC regional difference version of FAC-010-2 Requirements 1.1 through 1.3 and FAC-011-2 Requirement 1.1 through 1.3.5.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 99	5/29/2009
S- Ref 10678 The Commission directs WECC to assign a Severe violation severity level to the WECC regional difference FAC-010-2 Requirement 1.1 and FAC-011-2 Requirement 1.1. In addition, the Commission directs WECC to apply a Severe violation severity level to the WECC regional difference FAC-010-2 Requirement 1.2 through 1.3 and FAC-011-2 Requirements 1.2 through 1.3.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 100 Sen 2	5/29/2010
S- Ref 10679 The Commission directs the ERO to file revised violation risk factors and violation severity levels for the regional difference within 30 days of the effective date of this final rule.	Version Two Facilities Design, Connections and Maintenance Reliability Standards	3/20/2009	Order 722	RM08-11-000	Para 100 Sen 5	7/6/2009
S- Ref 10680 - ...directs the ERO to develop a modification to Reliability Standard CIP-006-2, through the NERC Reliability Standards development process, to add a requirement on visitor control programs, including the use of visitor logs to document entry and exit, within 90 days from the date of this order.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para 30	12/29/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10681 - ...direct the ERO to develop a modification to Reliability Standard CIP-006-2, through the NERC Reliability Standards development process, to add a requirement on visitor control programs, including the use of visitor logs to document entry.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para 30	12/29/2009
S- Ref 10682 - ...direct the ERO to develop a modification to Reliability Standard CIP-008-2, Requirement R1.6, through the NERC Reliability Standards development process, to remove the last sentence of CIP-008-2 Requirement R1.6.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para 38	12/29/2009
S- Ref 10683 - ...direct the ERO to develop a modification to Reliability Standard CIP-008-2, Requirement R1.6, through the NERC Reliability Standards development process, to remove the last sentence of CIP-008-2 Requirement R1.6.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para 38	12/29/2009
S- Ref 10684 - ...direct NERC to submit, within 90 days of the date of issuance of this order, a compliance filing that includes a revised Version 2 Implementation Plan, addressing the Version 2 CIP Reliability Standards, that clarifies the matters specified in the attachment to this order.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para 41	12/29/2009
S- Ref 10685 - ...We direct NERC to submit, within 90 days of the date of issuance of this order, a compliance filing that includes a revised Version 2 Implementation Plan, addressing the Version 2 CIP Reliability Standards, that clarifies the matters specified in the attachment to this order.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para 41	12/29/2009
S- Ref 10686 - ...direct NERC to submit as part of the compliance filing required by this order an update of the timetable that reflects the plan to address remaining Commission directives from Order No. 706.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para 44	12/29/2009

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10687 - ...direct NERC to submit as part of the compliance filing required by this order an update of the timetable that reflects the plan to address remaining Commission directives from Order No. 706.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para 44	12/29/2009
S- Ref 10688 - …directs NERC to develop modifications to the CIP Reliability Standards using its Reliability Standards Development Process within 90 days of the date of this order, as discussed in the body of this order.	Order Approving Revised Reliability Standards for CIP - Docket No. RD09-7	9/30/2009	128 FERC ¶ 61,291	RD09-7-000	Para C	12/29/2009
S- Ref 10689 - ...directs NERC to make a compliance filing within thirty days of the date of this order submitting to the Commission the following information: ● the anticipated date the scope of systems determination framework will be finalized; ● the status of the development of the exemption process; ● whether the exemption process will include: (i) an application deadline and (ii) a deadline for a determination on an exemption request; and ● a description of any other time parameters that may be included in the exemption process."	Order Denying Rehearing and Granting Clarification - Docket No. RM06-22-010	12/17/2009	129 FERC ¶ 61,224	RM06-22-010	Para 14	1/19/2010
S- Ref 10690 - ...direct NERC to submit as part of its compliance filing, a revised Implementation Plan that incorporates Version 2 CIP Standards into the Implementation Plan schedule.	Order Denying Rehearing and Granting Clarification - Docket No. RM06-22-010	12/17/2009	129 FERC ¶ 61,224	RM06-22-010	Para 15	1/19/2010

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10691 - Further, in future filings proposing modifications to the CIP Standards, NERC must address how owners and operators of nuclear power plants located in the United States will implement the revised CIP Standards and whether owners and operators can implement the revised CIP Standards under the proposed Implementation Plan. If NERC does not believe that such future modifications can be implemented under the Implementation Plans schedule, NERC must propose in the filing a new implementation plan addressing nuclear power plant owners and operators compliance with the proposed modifications.	Order Denying Rehearing and Granting Clarification - Docket No. RM06-22-010	12/17/2009	129 FERC ¶ 61,224	RM06-22-010	Para 16	1/19/2010
S- Ref 10692 - ERO should consider the appropriateness of developing a memorandum of understanding with the NRC, or revising existing agreements, to address such matters as NRC staff consultation in the exception application process and sharing of Safeguard Information.	Order Denying Rehearing and Granting Clarification - Docket No. RM06-22-010	12/17/2009	129 FERC ¶ 61,224	RM06-22-010	Para 17	1/19/2010
S- Ref 10693 - Revise section 1.3 as necessary to designate CIP-006-1 R1.1 as an Applicable Requirement subject to the TFE procedure.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 20	4/21/2010
S- Ref 10694 - ...direct the ERO to submit a compliance filing, within 90 days of the date of this order, identifying the purpose of a Class-Type TFE list and defining the process for identifying Class-Type TFEs and the procedure for publishing and maintaining the Class-Type TFE list.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 27	4/21/2010

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10695 - …directs NERC to provide a semi-annual, non-public report to the Commission tracking additions, modifications, and deletions to the Class-Type TFE list and describing the reasons behind the changes.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 28	1/1/2012
S- Ref 10696 - ...direct NERC: (1) to designate which entity or entities will determine under section 3.1(iv) what safety risks or issues outweigh the benefits of Strict Compliance with the Applicable Requirement, (2) to designate the entity or entities responsible for determining under section 3.1(vi) what costs far exceed the benefits to the reliability of the Bulk Electric System, and (3) to specify the manner in which reliability benefits are intended to be quantified to make this determination.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 32	4/21/2010
S- Ref 10697 - …direct NERC to modify section 3.2 of Appendix 4D to require any alternative means of compliance to achieve a comparable level of security as Strict Compliance with the requirement.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 35	4/21/2010
S- Ref 10698.2 - ...direct NERC to establish a uniform set of required information for the Part A submission and incorporate it in into its Rules of Procedure. Creating a uniform set of required information will ensure consistency among the regions and will ensure that NERC is receiving all of the information necessary to prepare its required reports.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 38	4/21/2010

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10698.1 - ...directs NERC to establish a uniform set of required information for the Part A submission and incorporate it in into its Rules of Procedure. Creating a uniform set of required information will ensure consistency among the regions and will ensure that NERC is receiving all of the information necessary to prepare its required reports.	Order Denying Rehearing and Granting Clarification - Docket No. RM06-22-010	12/17/2009	129 FERC ¶ 61,224	RM06-22-010	Para 14	1/19/2010
S- Ref 10699 - Due to concerns over the frequency and complexity of TFE use as well as concerns over both time and the adequacy of Regional Entity resources, the Commission believes that the burden of establishing a valid TFE should remain squarely with the Responsible Entity requesting it. Accordingly, we direct NERC to change section 5.2.5 of Appendix 4D to address this concern.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 42	4/21/2010
S- Ref 10700 - The Commission approves section 5.3 and also directs NERC to revise this section as discussed below. NERC must submit revisions to section 5.3 in a compliance filing within ninety days of the date of this order.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 45	4/21/2010
S- Ref 10701 - ...direct NERC to use, on an interim basis until NERC files and the Commission approves the compliance filing addressing this issue, an outer limit on Effective Dates of no longer than 60 days after issuance of a notice of rejection and no longer than 90 days after the issuance of a notice of disapproval.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 46	4/21/2010
S- Ref 10702 - If the Regional Entity determines that exceptional circumstances warrant an Effective Date that is after the proscribed outer limit, we direct the Regional Entity to provide a detailed explanation of such determination in the notice of rejection/disapproval to the Responsible Entity and to provide a copy of such notice to NERC.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 47	4/21/2010

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10703 - The Commission will not tolerate TFE Requests that were not made in good faith or that were fraudulent and we fully expect NERC and Regional Entity staff to monitor TFE requests to detect the misuse of the exceptions procedure. Accordingly, the Commission directs NERC to add a provision to this effect in its 90-day compliance filing.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 48	4/21/2010
S- Ref 10704 - NERCs annual report to the Commission should address circumstances and justifications for TFEs and the mitigation measures used to address vulnerabilities.	Order Approving Technical Feasibility Exception Procedures and Ordering Compliance Filing	1/21/2010	130 FERC ¶ 61,050	RR10-1-000	Para 32 Footnote 44	9/28/2011
S- Ref 10705 - ...direct the ERO to submit a modification to Table I, footnote b of Reliability Standard TPL-002-0 that complies with the Commissions directive in Order No. 693, by June 30, 2010.	Order Setting Deadline for Compliance - Docket No. RM06-16-009	3/18/2010	130 FERC ¶ 61,200	RM06-16-009	Para 8	3/31/2011 (FERC proposed remand)
S- Ref 10706 - ...directs NERC to make a compliance filing submitting implementation plans for the implementation of Versions 2 and 3 of the CIP Standards by owners and operators of U.S. nuclear power plants on the same schedule established for Version 1 under the Implementation Plan.	Order Addressing Compliance Filing and Approving Implementation Plan	3/18/2010	130 FERC ¶ 61,185	RM06-22-011	Para 2	11/30/2010
S- Ref 10707 - Should NERC become aware that it will be unable to complete the scope of systems determinations within NERCs projected timeframe (R + 8 months), NERC must timely notify the Commission of the reason for the delay and propose an alternate deadline.	Order Addressing Compliance Filing and Approving Implementation Plan	3/18/2010	130 FERC ¶ 61,185	RM06-22-011	Para 20	11/30/2010
S- Ref 10708 - ...direct NERC to submit a compliance filing modifying 57 sets of Violation Severity Level assignments within 60 days of the issuance of this order.	Order Addressing VSL Assignments for CIP Reliability Standards - Docket No. RM06-22-008	3/18/2010	130 FERC ¶ 61,211	RM06-22-008	Para 1	5/17/2010

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10709 - ...direct NERC to revise seventeen sets of Violation Severity Level assignments, specified in the Appendix, to address interdependency concerns discussed above.	Order Addressing VSL Assignments for CIP Reliability Standards - Docket No. RM06-22-008	3/18/2010	130 FERC ¶ 61,211	RM06-22-008	Para 23	5/17/2010
S- Ref 10710 - ...direct NERC to revise specific Violation Severity Level assignments, specified in the Appendix, to address the concern described above about levels of non-compliance.	Order Addressing VSL Assignments for CIP Reliability Standards - Docket No. RM06-22-008	3/18/2010	130 FERC ¶ 61,211	RM06-22-008	Para 27	5/17/2010
S- Ref 10711 - ...direct NERC to remove the extraneous language concerning the date of training.	Order Addressing VSL Assignments for CIP Reliability Standards - Docket No. RM06-22-008	3/18/2010	130 FERC ¶ 61,211	RM06-22-008	Para 32	5/17/2010
S- Ref 10712 - ...direct the ERO to revise certain Violation Severity Level assignments to remove ambiguity and improve consistency, as set forth in the Appendix.	Order Addressing VSL Assignments for CIP Reliability Standards - Docket No. RM06-22-008	3/18/2010	130 FERC ¶ 61,211	RM06-22-008	Para 33	5/17/2010
S- Ref 10713 - Also, pursuant to section 215(d)(5) of the FPA, the Commission adopts some of the proposed modifications in the NOPR and thus directs certain modifications to the Reliability Standard. Unless stated otherwise, the Commission directs the ERO to submit these modifications no later than one year from the date of this Final Rule.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 16	3/18/2011
S- Ref 10714 - ...direct the ERO to modify PRC-023-1 to apply an add in approach to certain sub-100 kV facilities that Regional Entities have already identified or will identify in the future as critical facilities for the purposes the Compliance Registry.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 47	3/18/2011

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10715 - …direct the ERO to modify Requirement R3 of the Reliability Standard to include the test that planning coordinators must use to identify sub-200 kV facilities that are critical to the reliability of the bulk electric system.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 47 Sen 3	3/18/2011
S- Ref 10716 - ...direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to identify all critical facilities.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 50	3/18/2011
S- Ref 10717 - ...direct the ERO to modify PRC-023-1 to apply an “add in” approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 60	3/18/2011
S- Ref 10718 - ...direct that additions to the Regional Entities critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 60	3/18/2011
S- Ref 10719 - ...direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 69	3/18/2011
S- Ref 10720 - ...direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 69	3/18/2011

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10721 - The ERO must develop a test that: (a) defines expectations of desirable system performance; and (b) describes the steady state and dynamic base cases that the planning coordinator must use in its assessments to carry out Requirement R3. The goal of the test must be consistent with the general reliability principles embedded in the existing series of TPL, Transmission Operations (TOP), Reliability Coordination (IRO), and Protection and Control (PRC) Reliability Standards.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 80	3/18/2011
S- Ref 10722 - ...direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 97	3/18/2011
S- Ref 10723 - …direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit a proposed Reliability Standard addressing generator relay loadability.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 105	7/16/2010
S- Ref 10724 - ...expect the ERO to develop the Reliability Standard addressing generator relay loadability as a new Standard, with its own individual timeline, and not as a revision to an existing Standard.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 106 (See also Para 104 - 105	9/30/2013
S- Ref 10725 - ...direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 150	3/18/2011
S- Ref 10726 - ...direct the ERO to file a report no later than 120 days of this Final Rule addressing the issue of protective relay operation due to power swings.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 150	7/16/2010

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10727 - direct the ERO to develop a Reliability Standard addressing undesirable relay operation due to stable power swings. Order 733-A P104: We deny rehearing and provide the following clarification. We continue to believe that not addressing stable power swings constitutes a gap in the current Reliability Standards and must be addressed. Therefore, we retain the directive, pursuant to section 215(d)(5) to direct the ERO to develop a Reliability Standard addressing stable power swings.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733; Order 733-A	RM08-13-000	Order 733 Para 153; Order 733-A Para 104	12/31/2014
S- Ref 10728 - …direct the ERO to consider islanding strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 162	12/31/2014
S- Ref 10729 - ...direct the ERO to develop a new Reliability Standard that prevents protective relays from operating unnecessarily due to stable power swings by requiring the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases-out relays that cannot meet this requirement. Order 733-B: Our directive does not require the elimination of the currently used impedance (or distance) relays as backup protection. Nor does it mandate use of a particular technology or an absolute obligation to prevent protection relays from operating unnecessarily during power stable swings. Our directive instead requires "the creation of a Reliability Standard that addresses protection systems vulnerable to stable power swings (resulting from Category B and Category C contingencies) that will result in in appropriate tripping."	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733; Order 733-B	RM08-13-000	Order 733 Para 173; Order 733-B Para 18	12/31/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10730 - ...direct the ERO to modify PRC-023-1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 186	3/18/2011
S- Ref 10731 - ...direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 203	3/18/2011
S- Ref 10732 - ...direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 224	3/18/2011
S- Ref 10733 - ...direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 237	3/18/2011
S- Ref 10734 - ...direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 244	3/18/2011
S- Ref 10735 - ...direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 264	3/18/2011
S- Ref 10736 - ...direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 283	3/18/2011

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10737 - ...direct the ERO to remove the exceptions footnote from the Effective Dates section.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 284	3/18/2011
S- Ref 10738 - …direct the ERO to assign a high violation risk factor to Requirement R3 and to file the new violation risk factor no later than 30 days after the date of this Final Rule.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 297	4/19/2010
S- Ref 10739 - ...direct the ERO to assign a single violation severity level of severe for violations of Requirement R1.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 308	4/19/2010
S- Ref 10740 - ...direct the ERO to change the violation severity level assigned to Requirement R2 from lower to severe to be consistent with Guideline 2a.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 310	4/19/2010
S- Ref 10741 - ...direct the ERO to assign a severe violation severity level to Requirement R3.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 311	4/19/2010
S- Ref 10742 - ...direct the ERO to file the new violation severity levels described in our discussion no later than 30 days after the date of this Final Rule.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 312	4/19/2010
S- Ref 10743 - ...direct that the ERO submit, within 30 days after the technical conference, a proposed schedule that includes interim targets for completing studies and analyses needed to develop a frequency response requirement, and a firm compliance deadline for submission of a modified Reliability Standard that is responsive to the Commission directives in Order No. 693 pertaining to Reliability Standard BAL-003-0.	Order Granting Rehearing for Further Consideration and Scheduling Technical Conference - Docket No. RM06-16-011	5/13/2010	131 FERC ¶ 61,136	RM06-16-011	Para 15	10/25/2010

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10744 - ...direct NERC to consider the following practices for use during the Standards development process as possible means to accomplish these objectives: (1) posting proposed regional Reliability Standards for comment from the continent-wide pool of interested stakeholders for consideration, while allowing the regional open processes to make final determinations to be submitted to NERC; (2) providing for comments from NERC technical staff on proposed regional Reliability Standards; and (3) including regional Reliability Standards in other NERC review processes that it uses for continent-wide Reliability Standards. We further direct NERC to discuss its considerations regarding these suggestions in the informational filing due six months from the date of this order.	Order on the Electric Reliability Organization's Three-year Performance Assessment	9/16/2010	3-yr assessment Docket Nos. RR09-7-000 and AD10-14-000	RR09-7-000; AD10-14-000	Para 76	3/16/2011
S- Ref 10745 - ...direct NERC to submit quarterly reports for an additional three years from the date of the order. In addition to the contents described in the January 2007 order, the quarterly reports must include separate analyses of: (i) the time required to complete projects (i.e., excluding urgent action projects); (ii) the time required to complete projects initiated in response to NERC's urgent action progress (including whether or not a permanent fix was implemented within the sunset period); and (iii) the time required to complete projects in response to Commission directives.	Order on the Electric Reliability Organization's Three-year Performance Assessment	9/16/2010	3-yr assessment Docket Nos. RR09-7-000 and AD10-14-000	RR09-7-000; AD10-14-000	Para 85	5/2/2011
S- Ref 10746 - Rather than devising a revised exemption process in the Final Rule, we direct the ERO to develop a proposed exemption process.	Revision to ERO Definition of BES	11/18/2010	Order 743	RM09-18-000	Para 112	1/25/2012

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10747 - ...direct that the ERO submit, within 30 days after the technical conference, a proposed schedule that includes interim targets for completing studies and analyses needed to develop a frequency response requirement, and a firm compliance deadline for submission of a modified Reliability Standard that is responsive to the Commission directives in Order No. 693 pertaining to Reliability Standard BAL-003-0.	Revision to ERO Definition of BES	11/18/2010	Order 743	RM09-18-000	Para 131	1/25/2012
S- Ref 10748 - The Commission directs the ERO to revise the definition of bulk electric system through the NERC Standards Development Process to address the Commissions concerns discussed herein.	Revision to ERO Definition of BES	11/18/2010	Order 743	RM09-18-000	Para 16	1/25/2012
S- Ref 10749 - Rather than devising a revised exemption process in the Final Rule, we direct the ERO to develop a proposed exemption process.	Revision to ERO Definition of BES	11/18/2010	Order 743	RM09-18-000	Para 30	1/25/2012
S- Ref 10750 - ...direct the ERO to consider these comments regarding radial facilities in crafting an exemption methodology	Revision to ERO Definition of BES	11/18/2010	Order 743	RM09-18-000	Para 55	1/25/2012
S- Ref 10751 - ...direct NERC, in a compliance filing due within 45 days of the date of the order, to identify the entity or entities that are responsible under Reliability Standard BAL-006-2 for calculating Inadvertent Interchange inside the MISO area.	ORDER APPROVING REVISIONS TO TWO RELIABILITY STANDARDS AND DIRECTING A COMPLIANCE FILING	1/6/2011	134 FERC ¶ 61,007 Order Approving Reliability Standards	RD10-04-000	Para 6 and 9	2/22/2011
S- Ref 10752 - The Commission directs RFC to add time horizons to the two main requirements when RFC reviews BAL-502-RFC-02 at the scheduled five-year review.	Final Rule Approving Planning Resource Adequacy Assessment Standard BAL-502-RFC-02	3/17/2011	Order 747	RM10-10-000;	Para 53	Regional

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S- Ref 10753 - Consider, at the time of its five-year review, whether to add a requirement to BAL-502-RFC-02 that would require Planning Coordinators to identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis.	Final Rule Approving Planning Resource Adequacy Assessment Standard BAL-502-RFC-02	3/17/2011	Order 747	RM10-10-000;	Para 65	Regional
S- Ref 10754 - The Commission requests that the NERC Reliability Coordinators Working Group engage the issues raised in this proceeding with NERC stakeholders, including the NERC Planning and Operating committees, to determine whether a need exists to further refine the delineation of responsibilities between the reliability coordinator and transmission operator for analyzing a class of grid-impactive SOLs.	Final Rule Approving Interconnection Reliability Operating Limits Standards	3/17/2011	Order 748	RM10-15-000	Para 44	3/18/2015 Not Standards' Related (OC PC SubC)
S- Ref 10755 - The Reliability Coordinator Working Group should further study the issue of requiring both the reliability coordinator and transmission operator to develop action plans for every SOL may add confusion to the process and determine if there is a need for reliability coordinators to have action plans developed and implemented with respect to certain grid-impactive SOLs.	Final Rule Approving Interconnection Reliability Operating Limits Standards	3/17/2011	Order 748	RM10-15-000	Para 55 and 52	3/18/2015 Not Standards' Related (OC PC SubC)
S- Ref 10756 - ...directs NERC to remove the WECC regional definition of Disturbance from the NERC Glossary to ensure consistency between the regional and NERC defined terms.	Final Rule on Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive	4/21/2011	Order 751	RM09-9-000	Para 13	2/25/2013

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10757 - The Commission directs WECC to submit revisions to or explanations justifying specific violation risk factors and violation severity levels within 60 days from the issuance of Order 751.	Final Rule on Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive	4/21/2011	Order 751	RM09-9-000	Para 133 and 129 - 132	6/20/2011
S- Ref 10761 - The Commission directs WECC to file, within 60 days from the issuance of this Final Rule, its criterion for identifying and modifying major transmission paths listed in the WECC Transfer Path Table.	Final Rule on Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive	4/21/2011	Order 751	RM09-9-000	Para 24	6/20/2011
S- Ref 10762 - The Commission recommends that WECC consider the comments of Bonneville, PacifiCorp and TANC when it develops future modifications to FAC-501-WECC-1.	Final Rule on Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive	4/21/2011	Order 751	RM09-9-000	Para 32, 28, and 29	6/20/2011
S- Ref 10763 - ...direct WECC to file, within 60 days from the issuance of this Final Rule, its criteria for identifying and modifying major transmission paths listed in the WECC Transfer Path Table and major remedial actions schemes listed in the WECC Remedial Action Schemes Table.	Final Rule on Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive	4/21/2011	Order 751	RM09-9-000	Para 41	6/20/2011

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10764 - ...encourage WECC to consider the comments of Mariner in during the development of VAR-002-WECC-1 in its Project WECC-0046.	Final Rule on Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive	4/21/2011	Order 751	RM09-9-000	Para 67 and 63	2/25/2013
S- Ref 10765 - The Commission directs WECC to file, within 60 days from the issuance of Order 752, WECCs criteria for identifying and modifying major transmission paths listed in the WECC Transfer Path Table.	Final Rule on TOP-007-WECC-1	4/21/2011	Order 752	RM09-14-000	Para 43	6/20/2011 (WECC) and 7/21/2011 (NERC)
S- Ref 10766 - The Commission directs WECC to file, within 120 days from the issuance of Order 752, a modification to the VRF for Requirement R1 of TOP-007-WECC-1.	Final Rule on TOP-007-WECC-1	4/21/2011	Order 752	RM09-14-000	Para 50 and 49	6/20/2011 (WECC) and 7/21/2011 (NERC)
S- Ref 10767 - The Commission directs WECC to file, within 120 days from the issuance of Order 752, a modification to the VRF for Requirement R2 of TOP-007-WECC-1.	Final Rule on TOP-007-WECC-1	4/21/2011	Order 752	RM09-14-000	Para 51	6/20/2011 (WECC) and 7/21/2011 (NERC)
S- Ref 10768 - The Commission directs WECC to file, within 120 days from the issuance of Order 752, modifications to the VSLs for TOP-007-WECC-1 to reflect NERCs approved table format.	Final Rule on TOP-007-WECC-1	4/21/2011	Order 752	RM09-14-000	Para 53	6/20/2011 (WECC) and 7/21/2011 (NERC)
S- Ref 10769 - ...direct the ERO to re-file the violation risk factors associated with the Requirements of PRC-023-1 when it submits its comprehensive plan.	Transmission Relay Loadability Reliability Standard - Docket No. RM08-13	3/18/2010	Order 733	RM08-13-000	Para 295 Footnote 197	4/19/2010

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10780 - The Commission remands to the ERO the proposed interpretation of VAR-001-1, Requirement R4 and directs the ERO to revise the interpretation consistent with the Commissions discussion below. [Note: see the Order Issued on May 21, 2009 for the complete details.]	Electric Reliability Organization Interpretations of Specific Requirements of Frequency Response and Bias and Voltage and Reactive Control Reliability Standards	5/21/2009	Order 724	RM08-16-000	Para 47	6/9/2014
S- Ref 10781 - We note that, with respect to the Critical Infrastructure Protection (CIP) Reliability Standards, NERC has developed a separate implementation plan that essentially gives responsible entities some lead time before newly acquired assets must be in compliance with the effective CIP Reliability Standards. We direct NERC to consider the necessity of developing a similar implementation plan with respect to PER-005-1, Requirement R3.1.	System Personnel Training Reliability Standards	11/18/2010	Order 742	RM09-25-000	Para 24	3/7/2014
S- Ref 10782 - ...direct the ERO to develop through a separate Reliability Standards development project formal training requirements for local transmission control center operator personnel.	System Personnel Training Reliability Standards	11/18/2010	Order 742	RM09-25-000	Para 64	3/7/2014
S- Ref 10783 - ...directs NERC to develop a definition of local transmission control center in the standards development project for developing the training requirements for local transmission control center operator personnel.	System Personnel Training Reliability Standards	11/18/2010	Order 742	RM09-25-000	Para 64	3/7/2014
S- Ref 10784 - …encourage NERC to complete its generic performance measures project.	System Personnel Training Reliability Standards	11/18/2010	Order 742	RM09-25-000	Para 70	6/12/2012

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S- Ref 10785 - Once the Standard is effective, if industry determines that ambiguity with the term arises, it would be appropriate for NERC to consider its proposal to develop a guideline to aid entities in their compliance obligations.	System Restoration	3/17/2011	Order 749	RM10-16-000	Para 24 and 18	3/27/2017
S- Ref 10786 - NERC should close the gap in the applicability of the draft COM-001-2 so it addresses generation operators and distribution providers.	System Restoration	3/17/2011	Order 749	RM10-16-000	Para 28	5/14/2014
S- Ref 10787 - ...encourage NERC to consider the comments of PacifiCorp regarding the development of a continent-wide definition of Functionally Equivalent Protection System and Functionally Equivalent Remedial Action Scheme during the development of Project 2009-07.	Final Rule on Version One Regional Reliability Standards for Facilities Design, Connections, and Maintenance; Protection and Control; and Voltage and Reactive	4/21/2011	Order 751	RM09-9-000	Para 50 and 47	Not standards' related (RAPA) 3/5/2013
S- Ref 10788 - …direct NERC to make an informational filing within six months of the date of the issuance of Order 754 explaining whether there is a further system protection issue that needs to be addressed.	Order Approving Interpretation of Transmission Planning Reliability Standard in Docket No. RM10-6-000	9/15/2011	Order 754	RM10-6-000	Para 20	3/15/2012
S- Ref 10789 - …direct NERC to either provide additional justification for these VRF designations or propose a revised VRF designation that addresses our concerns.	Order Approving Reliability Standard FAC-013-2	11/17/2011	137 FERC ¶ 61,131 Order Approving FAC-013-2	RD11-3-000	Para 23	1/17/2012
S- Ref 10790 - …direct NERC to modify the VSL language for Requirement R1 to correct a typographical error.	Order Approving Reliability Standard FAC-013-2	11/17/2011	137 FERC ¶ 61,131 Order Approving FAC-013-2	RD11-3-000	Para 27	1/17/2012

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S- Ref 10791 - …direct NERC to submit a compliance filing by January 16, 2012 to correct VSLs and VRFs.	Order Approving Reliability Standard FAC-013-2	11/17/2011	137 FERC ¶ 61,131 Order Approving FAC-013-2	RD11-3-000	Para 28	1/17/2012
S- Ref 10792 - …direct the ERO to modify the VRF assignment for FAC-008-3, Requirement R2 to medium and to submit the modification in a compliance filing within 60 days from the date this order issues (by January 16, 2012).	Order Approving Reliability Standard FAC-008-3	11/17/2011	137 FERC ¶ 61,123 Order Approving FAC-008-3	RD11-10-000	Para 24	1/17/2012
S- Ref 10793 ...direct the ERO to consult with federal entities that are required to comply with both CIP Reliability Standards and NIST standards on the effectiveness of the NIST standards and on implementation issues and report these findings to the Commission.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 233 (See also Para 25)	1/31/2013
S- Ref 10794 - ...direct the ERO to consider the comment from ISA99 Team [ISA99 Team objects to the exclusion of communications links from CIP-002-1 and non-routable protocols from critical cyber assets, arguing that both are key elements of associated control systems.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 285 (See also 278)	1/31/2013
S- Ref 10795 - ...direct that the ERO develop through its Reliability Standards development process a mechanism for external review and approval of critical asset lists.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 322 (See also 323 - 325)	2/10/2011
S- Ref 10796 - ...direct the ERO, using its Reliability Standards development process, to develop a process of external review and approval of critical asset lists based on a regional perspective.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 329 (See also 327 - 328)	2/10/2011
S- Ref 10797 - …direct the ERO to clarify that the exceptions mentioned in Requirements R2.3 and R3 of CIP-003-1 do not except responsible entities from the Requirements of the CIP Reliability Standards.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 376	1/31/2013

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S- Ref 10798 - ...direct the ERO to develop modifications to Reliability Standards CIP-003-1, CIP-004-1, and/or CIP-007-1, to ensure and make clear that, when access to protected information is revoked, it is done so promptly.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 386	1/31/2013
S- Ref 10799 - ...direct the ERO to consider, in developing modifications to CIP-004-1, whether identification of core training elements would be beneficial and, if so, develop an appropriate modification to the Reliability Standard.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 433	1/31/2013
S- Ref 10800 - ...direct the ERO to modify Requirement R2 of CIP-004-1 to clarify that cyber security training programs are intended to encompass training on the networking hardware and software and other issues of electronic interconnectivity.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 434	1/31/2013
S- Ref 10801 - …direct the ERO to determine what, if any, modifications to CIP-004-1 should be made to assure that security trainers are adequately trained themselves.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 435	1/31/2013
S- Ref 10802 - ...direct the ERO to develop modifications to CIP-004-1 to require immediate revocation of access privileges when an employee, contractor or vendor no longer performs a function that requires physical or electronic access to a critical cyber asset for any reason (including disciplinary action, transfer, retirement, or termination).	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 460	1/31/2013
S- Ref 10803 - ...direct the ERO to modify Requirement R4 to make clear that unescorted physical access should be denied to individuals that are not identified on the authorization list, with clarification.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 464	1/31/2013
S- Ref 10804 - The ERO should consider the suggestions raised by Northern Indiana, SPP and NRECA in the Reliability Standards development process.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 475 (See also para 470 - 472)	1/31/2013

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S- Ref 10805 - ...direct the ERO to modify CIP-004-1, and other CIP Reliability Standards as appropriate, through the Reliability Standards development process to address critical cyber assets that are jointly owned or jointly used.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 476 (See also para 473 and 466 - 468)	1/31/2013
S- Ref 10806 - ...direct the ERO to identify examples of specific verification technologies that would satisfy Requirement R2.4, while also allowing compliance pursuant to other technically equivalent measures or technologies.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 511	1/31/2013
S- Ref 10807 - The Commission adopts the CIP NOPR proposal to require the ERO to modify CIP-005-1 to require logs to be reviewed more frequently than 90 days.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 525	1/31/2013
S- Ref 10808 - …direct the ERO to modify CIP-005-1 through the Reliability Standards development process to require manual review of those logs without alerts in shorter than 90 day increments.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 526	1/31/2013
S- Ref 10809 - …direct the ERO to modify CIP-005-1 to require some manual review of logs, consistent with our discussion of log sampling below, to improve automated detection settings, even if alerts are employed on the logs.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 526	1/31/2013
S- Ref 10810 - The Commission clarifies its direction with regard to reviewing logs. In directing manual log review, the Commission does not require that every log be reviewed in its entirety. Instead, the ERO could provide, through the Reliability Standards development process.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 528	1/31/2013
S- Ref 10811 - We adopt the EROs proposal to provide for active vulnerability assessments rather than full live vulnerability assessments.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 541	1/31/2013

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S- Ref 10812 - The Commission adopts the EROs recommendation of requiring active vulnerability assessments of test systems.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 542	1/31/2013
S- Ref 10813 - …direct the ERO to revise the Reliability Standard so that annual vulnerability assessments are sufficient, unless a significant change is made to the electronic security perimeter or defense in depth measure, rather than with every modification.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 544	1/31/2013
S- Ref 10814 - …direct the ERO to determine, through the Reliability Standards development process, what would constitute a modification that would require an active vulnerability assessment.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 544	1/31/2013
S- Ref 10815 - ...direct the ERO to develop a modification to CIP-006-1 to require a responsible entity to test the physical security measures on critical cyber assets more frequently than every three years.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 581	1/31/2013
S- Ref 10816 - ...direct the ERO to develop requirements addressing what constitutes a representative system and to modify CIP-007-1 accordingly.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 609 Sen 5	1/31/2013
S- Ref 10817 - ...direct the ERO to consider providing further guidance on testing systems in a reference document.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 609 Sen 6	1/31/2013
S- Ref 10818 - …direct the ERO to revise the Reliability Standard to require each responsible entity to document differences between testing and production environments.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 610	1/31/2013

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S- Ref 10819 - The Commission cautions that certain changes to a production or test environment might make the differences between the two greater and directs the ERO to take this into account when developing guidance on when to require updated documentation.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 611	1/31/2013
S- Ref 10820 - The Commission believe that NERC should register demand side aggregators if the loss of their load shedding capability, for reasons such as a cyber incident, would affect the reliability or operability of the Bulk-Power System.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 051	Not Standards' related (NERC Registration)
S- Ref 10821 - The Commission continues to believe that, in general, logs should be reviewed at least weekly and therefore adopts the CIP NOPR proposal to require the ERO to modify CIP-007-1 to require logs to be reviewed more frequently than 90 days, but leaves it to the Reliability Standards development process to determine the appropriate frequency, given our clarification below, similar to our action with respect to CIP-005-1.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 628	1/31/2013
S- Ref 10822 - The Reliability Standards development process should decide the degree to which the revised CIP-007-1 describes acceptable log sampling. The ERO could also provide additional guidance on how to create the sampling of log entries, which could be in a reference document.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 629	1/31/2013
S- Ref 10823 - ...direct the ERO to clarify what it means to prevent unauthorized retrieval of data from a cyber asset prior to discarding it or redeploying it.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 633	1/31/2013
S- Ref 10824 - ...direct the ERO to revise Requirement R7 of CIP-007-1 to clarify, consistent with this discussion, what it means to prevent unauthorized retrieval of data.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 635	1/31/2013

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S- Ref 10825 - ...direct the ERO to provide guidance regarding what should be included in the term reportable incident.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 660	1/31/2013
S- Ref 10826 - …direct the ERO to develop a modification to CIP-008-1 to: (1) include language that takes into account a breach that may occur through cyber or physical means; (2) harmonize, but not necessarily limit, the meaning of the term reportable incident with other reporting mechanisms, such as DOE Form OE 417; (3) recognize that the term should not be triggered by ineffectual and untargeted attacks that proliferate on the internet; and (4) ensure that the guidance language that is developed results in a Reliability Standard that can be audited and enforced.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 661	1/31/2013
S- Ref 10827 - ...direct the ERO to modify CIP-008-1 to require each responsible entity to contact appropriate government authorities and industry participants in the event of a cyber security incident as soon as possible, but, in any event, within one hour of the event, even if it is a preliminary report.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 673	1/31/2013
S- Ref 10828 - ...directs the ERO to modify CIP-008-1 to require a responsible entity to, at a minimum, notify the ESISAC and appropriate government authorities of a cyber security incident as soon as possible, but, in any event, within one hour of the event, even if it is a preliminary report.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 676	1/31/2013
S- Ref 10829 - ...direct the ERO to modify CIP-008-1, Requirement R2 to require responsible entities to maintain documentation of paper drills, full operational drills, and responses to actual incidents, all of which must include lessons learned.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 686	1/31/2013

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S- Ref 10830 - ...directs the ERO to include language in CIP-008-1 to require revisions to the incident response plan to address these lessons learned.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 686	1/31/2013
S- Ref 10831 - ...direct the ERO to modify CIP-009-1 to include a specific requirement to implement a recovery plan.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 694	1/31/2013
S- Ref 10832 - The Commission adopts the proposal to enforce this Reliability Standard such that, if an entity has the required recovery plan but does not implement it when the anticipated event or conditions occur, the entity will not be in compliance with this Reliability Standard.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 694	1/31/2013
S- Ref 10833 - ...direct the ERO to modify CIP- 009-1 to incorporate guidance that the backup and restoration processes and procedures required by Requirement R4 should include, at least with regard to significant changes made to the operational control system, verification that they are operational before the backups are stored or relied upon for recovery purposes.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 739	1/31/2013
S- Ref 10834 - ...direct the ERO to modify CIP-009-1 to provide direction that backup practices include regular procedures to ensure verification that backups are successful and backup failures are addressed, so that backups are available for future use.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 748	1/31/2013
S- Ref 10835 - ...direct NERC to submit a compliance filing containing the corrections noted in Appendix A of the letter Order issued on December 7, 2010 approving VSLs for FAC-014 -2 in Dockets RM08-11-002 and RM08-11-003 within 30 days of the date of the order.	Letter Order Approving VSLs for FAC-014 -2 in Dockets RM08-11-002 and RM08-11-003	12/7/2010	133 FERC ¶ 61,204	RM08-11-002; RM08-11-003	Para 006	1/6/2011

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S- Ref 10836 - …direct NERC to submit a compliance filing, by March 21, 2011, re-assigning a medium designation to the VRF for CIP-003-2 Requirement R2.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 015	3/21/2011
S- Ref 10837 - ...direct NERC to make specific changes to the Version 2 VSLs for CIP-004-2, CIP-005-2, and CIP-006-2 to conform to the determinations made in the CIP VSL Order for the version 1 CIP standards, based on CIP Guidelines 1 and 2, for parallel Requirement text.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 022	3/21/2011
S- Ref 10838 - ...direct NERC to make modifications to CIP-003-2 Requirements R2.1 and R3.2; CIP-004-2 Requirement R3; CIP-006-2 Requirements R1.7, R4, R6, and R7; CIP-007-2 Requirement R2, R2.3, R3, R3.2, R7, and R9; and CIP-008-2 Requirement R1 to remove ambiguity and improve consistency.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 023 Sen 3	3/21/2011
S- Ref 10839 - ...direct NERC to make a modification of the VSL for CIP-006-2 Requirement R3 to directly track the language of the new R3 as illustrated in Appendix 1 to the FERC Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002 issued January 20, 2011.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 023 Sen 7	3/21/2011
S- Ref 10840 - The Commission directs a specific modification to the VSL for CIP-009-2 Requirement R3, as illustrated in Appendix 1 to the FERC Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002 issued January 20, 2011.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 024	3/21/2011
S- Ref 10841 - The Commission directs specific modifications to the following VSLs: CIP-004-2 Requirements R1 and R2, CIP-006-2 Requirement R1.1, CIP-006-2 Requirement R1.2, and CIP-007-2 Requirement R9.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 025	3/21/2011

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10842 - …direct the ERO to modify the VSLs for CIP-007-2 Requirements R2.3 and R3.2, as illustrated in Appendix 1 to the FERC Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002 issued January 20, 2011.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 026	3/21/2011
S- Ref 10843 - ...direct NERC to provide, by March 21, 2011, a complete list of all Version 2 CIP Reliability Standard Requirements, and their associated VSLs and VRFs, as determined or carried forward by the FERC Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002 issued January 20, 2011.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 027	3/21/2011
S- Ref 10844 - The Commission directs specific modifications for the ERO to revise its proposed VSL for CIP-006-3 Requirement R1.6 as shown in Appendix 2 of the FERC Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002 issued January 20, 2011, and to add rows containing N/A for the new sub-requirements R1.6.1 and R1.6.2, consistent with how NERC has treated similar sub-requirements.	Order Approving VRFs and VLS for CIP Standards in Dockets RD10-6-000 and RD09-7-002	1/20/2011	134 FERC ¶ 61,045	RD10-6-000; RD09-7-002	Para 032	3/21/2011
S- Ref 10845 - The ERO should alleviate Northern Indiana's concern that documenting vulnerability test results or any mitigation or remediation plans may reveal system vulnerabilities by providing for such reports to be reviewed under the confidentiality provisions of its Rules of Procedure.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 612	1/31/2013
S- Ref 10846 - ...direct the ERO to modify Requirement R3 of CIP-009-1 to shorten the timeline for updating recovery plans.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 731	5/22/2009

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S- Ref 10847 - ...direct NERC to file a schedule/timeline for the development of technical documents, and associated reliability standard modifications, which 1) describe the devices and functions (to include sudden pressure relays which trip for fault conditions) that are designed to sense or take action against any abnormal system condition that will affect reliable operation of the bulk power system, and 2) propose minimum maintenance activities for such devices and maximum maintenance intervals, including the technical basis for each.	Order Approving Interpretation of Protection System Reliability Standard	2/3/2012	Order 758	RM10-5-000	Para 15	4/12/2012
S- Ref 10848 - ...direct NERC to include maintenance and testing of reclosing relays that can affect the reliable operation of the Bulk-Power System within Project 2007-17 or make an informational filing that provides a schedule for how NERC will address such issues.	Order Approving Interpretation of Protection System Reliability Standard	2/3/2012	Order 758	RM10-5-000	Para 27	2/14/2014
S- Ref 10849 - The ERO should consider the suggestion that the CIP Reliability Standards require oversight by a corporate officer (or the equivalent, since some entities do not have corporate officers) rather than by a "senior manager."	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 296 (See also para 289 - 293)	1/31/2013
S- Ref 10850 - ...direct the ERO to modify Requirement R3 of CIP-004-1 to provide that newly-hired personnel and vendors should not have access to critical cyber assets prior to the satisfactory completion of a personnel risk assessment, except in specified circumstances such as an emergency.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 443	5/22/2009
S- Ref 10851 - …direct the ERO to revise Requirement R8.4 to require an entity-imposed timeline for completion of the already-required action plan.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 643	1/31/2013

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S- Ref 10852 - The ERO should consider Northern Indiana's and Xcel's concerns regarding the phrase "single access point at the dial up device."	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 495	1/31/2013
S- Ref 10853 - ...direct the ERO to develop a requirement that use of the technical feasibility exception by a responsible entity must be accompanied by a remediation plan and timeline for elimination the use of the technical feasibility exception.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 192	5/22/2009
S- Ref 10854 - ...direct the ERO to modify Requirement R4 to include safeguards against personnel introducing, either maliciously or unintentionally, viruses or malicious software to a cyber asset within the electronic security perimeter through remote access, electronic media, or other means, consistent with our discussion above.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 622 Sen 2 (See also 614 and 619)	1/31/2013
S- Ref 10855 - ...clarify that CIP-008-1 should require a responsible entity to verify the list of entities that must be called pursuant to its cyber security incident response plan and that the contact numbers at those agencies are correct. The ERO may use a term different than full operational exercise when doing so.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 687	1/31/2013

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10856 - ...direct NERC to address four specific questions related to PRC-023-2 — Transmission Relay Loadability in a filing to the Commission on or before February 17, 2013: 1) A summary of the base cases used in applying the Attachment B criteria and an assessment of how the base cases used for the analysis relate to TPL-003-0, Requirement R1.3.2; 2) A discussion of the types of studies that planning coordinators may use to identify circuits under Attachment B; 3) An assessment that demonstrates whether Attachment B is comprehensive enough to capture all circuits that could have an operational impact on the reliability of the bulk electric system in the context of transmission relay laudability; and 4) relay loadability under the B4 criterion consistent with Requirement R1.	Order Approving Transmission Relay Loadability Reliability Standard PRC-023-2	3/15/2012	Order 759	RM11-16-000	Para 38 (See also Para 77 and 78)	2/19/2013
S- Ref 10857 - The Commission requires NERC to utilize its Expedited Reliability Standards Development Process to develop timely modifications to TPL-002-0b, Table 1 footnote 'b' to quickly respond to the remand of TPL-002-0b detailed in FERC Order 672.	Final Rule Remanding TPL-002-0b	4/19/2012	Order 762	RM12-1-000	Para 1 (See also Para 21)	5/21/2012
S- Ref 10858 - ...direct NERC to use section 1600 of its Rules of Procedure to obtain information from users, owners and operators of the bulk-power system to identify the specific instances of any planned interruptions of Firm Demand under footnote 'b' and how frequently the provision has been used.	Final Rule Remanding TPL-002-0b	4/19/2012	Order 762	RM12-1-000	Para 20	2/28/2013
S- Ref 10859 - The Commission directs NERC to consider some blend of quantitative and qualitative thresholds while developing a limited exception or planned interruption of Firm Demand.	Final Rule Remanding TPL-002-0b	4/19/2012	Order 762	RM12-1-000	Para 57 (See also para 54 - 56)	2/28/2013
S- Ref 10860 - The Commission established a deadline for NERC to file the Version 5 CIP Reliability Standards of March 31, 2013.	Order Approving Version 4 CIP Standards	4/19/2012	Order 761	RM11-11-000	Para 13 Sen 5	1/31/2013

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10861 - ...direct NERC to submit quarterly reports, at the beginning of each quarter, in which it is to both confirm that it is on track to meet the deadline of filing the Version 5 CIP Reliability Standards by March 31, 2013 and to describe the status of the Version 5 CIP Reliability Standards development efforts.	Order Approving Version 4 CIP Standards	4/19/2012	Order 761	RM11-11-000	Para 13 Sen 6	7/2/2012
S- Ref 10862 - …direct NERC to modify requirement R9 of PRC-006-1 to explicitly require corrective action in accordance with a schedule established by the planning coordinator.	Order Approving Automatic Underfrequency Load Shedding and Load Shedding Plans	5/7/2012	Order 763	RM11-20-000	Para 48	12/15/2014
S- Ref 10863 - The Commission directs NERC to submit a compliance filing within 30 days of the effective date of FERC Order 763 (approximately August 9, 2012) providing a plan for modifying PRC-006-1 to explicitly require corrective action in accordance with a schedule established by the planning coordinator (see directive 10862).	Order Approving Automatic Underfrequency Load Shedding and Load Shedding Plans	5/7/2012	Order 763	RM11-20-000	Para 48	8/9/2012
S- Ref 10864 - ...direct NERC to submit a revised VRF of Requirement R5 of PRC-006-1 and a revised set of VSLs for requirements R8 of PRC-006-1 within 30 days of the effective date of FERC Order 763 (approximately August 9, 2012).	Order Approving Automatic Underfrequency Load Shedding and Load Shedding Plans	5/7/2012	Order 763	RM11-20-000	Para 95	8/9/2012
S- Ref 10866 - ...direct NERC to implement exclusion E1 so that the exclusions for radial systems do not apply to tie-lines for bulk electric system generators identified in inclusion I2.	Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure	12/20/2012	Order 773	RM12-6-000 and RM12-7-000	Para 164 Sen 2 (See also Para 4, Para 167)	12/13/2013

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10867 - ...direct NERC to modify exclusion E3 to remove the 100 kV minimum operating voltage in the local network definition. Within 30 days of the effective date of this Final Rule, we direct NERC to submit a schedule outlining how and when it will make the modification to the definition.	Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure	12/20/2012	Order 773	RM12-6-000 and RM12-7-000	Para 199 Sen 7	4/4/2013
S- Ref 10868 - ...direct NERC to submit a compliance filing within one year of the implementation date identifying in sufficient detail the types of local network configurations that have been excluded from the bulk electric system under this exclusion.	Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure	12/20/2012	Order 773	RM12-6-000 and RM12-7-000	Para 206 Sen 3	Not standards' related 7/1/2015
S- Ref 10869 - ...direct NERC to implement exclusion E3 so that the exclusion for local networks does not apply to bulk electric system generator tie-lines operated at or above 100 kV as shown in the figure below.	Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure	12/20/2012	Order 773	RM12-6-000 and RM12-7-000	Para 214 Sen 3	12/13/2013
S- Ref 10870 - ...direct NERC to make an informational filing within 90 days of the effective date of this Final Rule detailing its plans to maintain a list and how it will make this information available to the Commission, Regional Entities, and potentially to other interested persons.	Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure	12/20/2012	Order 773	RM12-6-000 and RM12-7-000	Para 310 Sen 1	12/13/2013

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10871 - …a. "As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC must establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners. Left to NERC how to accomplish this objective. Commission identifies modification of FAC-014 as a vehicle that would meet the objective." (P 41) "NERC should inform the Commission of when it has developed means for communication of IROLs to transmission owners to help ensure that they receive notice of each of their applicable lines before the standard becomes effective as to those lines." (P 42)	Revisions to Reliability Standard for Transmission Vegetation Management	3/21/2013	Order 777	RM12-4-000	Para 6, 41, 42	Not standards' related
S- Ref 10872 - ...direct NERC to conduct or contract testing to develop empirical data regarding flashover distances between conductors and vegetation.	Revisions to Reliability Standard for Transmission Vegetation Management	3/21/2013	Order 777	RM12-4-000	Para 3, 59-63	Not standards' related (RAPA) 8/12/2015
S- Ref 10873.2 - …direct NERC, within 45 days of the effective date of this Final Rule, to submit an informational filing that includes, *inter alia*: (1) a schedule for testing, (2) a scope of work, (3) funding solutions, and (4) deadline for submitting a final report to the Commission on the test results (and interim reports if a multi-year study is conducted).	Revisions to Reliability Standard for Transmission Vegetation Management	3/21/2013	Order 777	RM12-4-000	Para 61 Sen 3	Not standards' related (RAPA) 7/12/2013
S- Ref 10873.1 -...direct NERC and SERC to make an informational filing within 30 days of the effective date of this final rule that provides a schedule for implementing the revision.	Regional Reliability Standard PRC-006-SERC-01 - Automatic Underfrequency Load Shedding Requirements	12/20/2012	Order 772	RM12-9-000	Para 25 Sen 7	3/11/2013

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10874.2 - ...direct NERC and SERC to modify the violation risk factor for regional Reliability Standard PRC-006-SERC-01, Requirement R6, from “medium” to “high.” NERC and SERC are directed to submit the revised violation risk factor within 30 days of the effective date of this final rule.	Regional Reliability Standard PRC-006-SERC-01 - Automatic Underfrequency Load Shedding Requirements	12/20/2012	Order 772	RM12-9-000	Para 32 Sen 1	3/11/2013
S- Ref 10874.1 - …direct NERC to modify the Violation Risk Factor for Requirement R2 from "medium" to "high" within 45 days of the effective date of the Final Rule.	Revisions to Reliability Standard for Transmission Vegetation Management	3/21/2013	Order 777	RM12-4-000	Para 73 Sen 1	7/12/2013
S- Ref 10875 - …NERC must consolidate the reference material and post it on the NERC website along with Reliability Standard FAC-003-2.	Revisions to Reliability Standard for Transmission Vegetation Management	3/21/2013	Order 777	RM12-4-000	Para 90 Sen 3	7/12/2013
S- Ref 10876 - Within six months of the effective date of this Final Rule, NERC must submit for approval one of more Reliability Standards that require owners and operators of the Bulk-Power System to develop and implement operational procedures to mitigate the effects of GMDs.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 2	11/14/2013
S- Ref 10877 - Within 18 months of the effective date of this final rule, NERC must submit for approval one or more Reliability Standards that require owners and operators of the Bulk-Power System to conduct initial and on-going vulnerability assessments of the potential impact of benchmark GMD events on Bulk-Power System equipment and the Bulk-Power System as a whole.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 2	1/21/2015

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10878 - The Second Stage GMD Reliability Standard must identify what severity GMD events (i.e. benchmark GMD events) that responsible entities will have to assess for potential impacts on the Bulk-Power System.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 2	1/21/2015
S- Ref 10879 - NERC must propose an implementation plan.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 91	1/21/2015
S- Ref 10880 - Consider the costs and benefits of particular mitigation measures as NERC develops the technically-justified Second Stager GMD Reliability Standard.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 28	1/21/2015
S- Ref 10881 - Consider tailoring of operational procedures based on the responsible entity's assessment of entity-specific factors, such as geography, geology, and system topology.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 38	11/14/2013
S- Ref 10882 - Consider operational procedures for restoring GMD-impacted portions of the Bulk-Power System that take into account the potential for damaged equipment that could be de-rated or out-of-service for an extended period of time.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 38	11/14/2013
S- Ref 10883 - The "Initial Actions" assessments provide a head start for analyzing the most at-risk and critical facilities before the Second Stage GMD Reliability Standards become effective and could be used to assist in performing the GMD vulnerability assessments required in the Second Stage GMD Reliability Standards.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 52	1/21/2015

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10884 - Consider identifying the benchmark GMD events that responsible entities would have to assess. Each responsible entity under the Second Stage GMD Reliability Standards would then be required to assess its vulnerability to the benchmark GMD events consistent with the five assessment parameters identified in the NOPR and adopted in this Final Rule.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 67	1/21/2015
S- Ref 10885 - Consider tasking planning coordinators, or another functional entity with a wide-area perspective, to coordinate mitigation plans across Regions under the Second Stage GMD Reliability Standards to ensure consistency and regional effectiveness.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 67, 82	1/21/2015
S- Ref 10886 - Consider developing Reliability Standard that can incorporate improvements in the scientific understanding of GMDs. When developing the Second Stage GMD Reliability Standards implementation schedule, NERC should consider the availability of validated tools, models, and data necessary to comply with the Requirements.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 68	1/21/2015
S- Ref 10887 - The Second Stage GMD Reliability Standards should require owners and operators of the Bulk-Power System 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.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 79, 81	1/21/2015
S- Ref 10888 - The responsible entities should perform vulnerability assessments of their own systems and develop the plans for mitigating any identified vulnerabilities.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 82	1/21/2015

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10889 - The Second Stage GMD Reliability Standards should not impose "strict liability" on responsible entities for failure to ensure the reliable operation of the Bulk-Power System in the face of a GMD event of unforeseen severity.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 84	1/21/2015
S- Ref 10890 - Consider how to verify that selected blocking measures are effective and consistent with the reliable operation of the Bulk-Power System.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 85	1/21/2015
S- Ref 10891 - Consider how the reliability goals of the proposed Reliability Standards can be achieved by a combination of automatic measures including, for example, some combination of blocking, improved "withstand" capability, instituting specification requirements for new equipment, inventory management, and isolating certain equipment that is not cost effective to retrofit.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 86	1/21/2015
S- Ref 10892 - Consider a multi-phased approach that requires owners and operators of the Bulk-Power System to prioritize implementation so that components considered vital to the reliable operation of the Bulk-Power System are protected first. That the implementation plan will take into account the availability of validated tools, models, and data that are necessary for responsible entities to perform the required GMD vulnerability assessments.	Reliability Standards for Geomagnetic Disturbances	5/16/2013	Order 779	RM12-22-000	Para 91	1/21/2015

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10893 - Direct NERC to report on the use of footnote 12 including the use and effectiveness of the local regulatory review and NERC review. This report is important because it will provide an analysis of the use of footnote 12, including but not limited to information on the duration, frequency and magnitude of planned non-consequential load loss, and typical (and if significant, atypical) scenarios where entities plan for non-consequential load loss.	Transmission Planning Reliability Standards	10/17/2013	Order 786	RM12-1-000 and RM13-9-000	Para 30	Not standards' related (RAPA)
S- Ref 10894 - Direct 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.	Transmission Planning Reliability Standards	10/17/2013	Order 786	RM12-1-000 and RM13-9-000	Para 40	
S- Ref 10895 - Direct NERC to modify Reliability Standard TPL-001-4, Requirement R1 and change its VRF from medium to high.	Transmission Planning Reliability Standards	10/17/2013	Order 786	RM12-1-001; RM13-9-001; RM13-11-001; RM13-16-001	Para 51	8/29/2014
S- Ref 10896 - Directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4.	Transmission Planning Reliability Standards	10/17/2013	Order 786	RM12-1-000 and RM13-9-000	Para 89	
S- Ref 10897 - Accordingly, the Commission directs NERC to develop modifications to the CIP version 5 Standards that address our concerns. Preferably, NERC should remove the "identify, assess, correct" language from the 17 CIP version 5 requirements. The Commission directs NERC to file these modifications for Commission approval within one year from the effective date of this Final Rule. Alternatively, NERC may develop a proposal to enhance the enforcement discretion afforded to itself and the Regional Entities, as discussed above.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 76 (See also 67 - 76)	2/13/2015

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S- Ref 10898 - We direct NERC to develop modifications to the CIP version 5 Standards to address this concern. We believe that NERC can effectively address this concern in a number of ways, including: (1) requiring specific controls for Low Impact assets, including subdividing the assets into different categories with Docket No. RM13-5-000 - different defined controls applicable to each subcategory; (2) developing objective criteria against which the controls adopted by responsible entities can be compared and measured in order to evaluate their adequacy, including subdividing the assets into different categories with different defined control objectives applicable to each subcategory; (3) defining with greater specificity the processes that responsible entities must have for Low Impact facilities under Reliability Standard CIP-003-5, Requirement R2; or (4) another equally efficient and effective solution. We believe that this approach allows NERC the flexibility to develop appropriate modification(s), while also considering the stakeholder concerns expressed in NOPR comments regarding the possible rigidity of requiring a "one-size-fits-all" set of controls.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 108	2/13/2015

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10899 - 124. Accordingly, the Commission directs NERC to conduct a survey of Cyber Assets that are included or excluded under the new BES Cyber Asset definition during the CIP version 5 Standards implementation periods. Such data will help provide a better understanding of the BES Cyber Asset definition. Based on the survey data, NERC should explain in an informational filing the following: (1) specific ways in which entities determine which Cyber Assets meet the 15 minute parameter; (2) types or functions of Cyber Assets that are excluded from being designated as BES Cyber Assets and the rationale as to why; (3) common problem areas with entities improperly designating BES Cyber Assets; and (4) feedback from each region participating in the implementation study on lessons learned with the application of the BES Cyber Asset definition. The informational filing should not provide a level of detail that divulges CEII data. This filing should also help other entities implementing CIP version 5 in identifying BES Cyber Assets. 125. The Commission directs NERC to submit the informational filing one year after the effective date of this Final Rule. Based on the information in the informational filing, the Commission may revisit whether the BES Cyber Asset definition should include the 15-minute parameter.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013; 3/20/2014	Order 791; See Order 791-A	RM13-5-000	Order 791: Para 124 and 125; Order 791-A Para 21	2/13/2015

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10900 - The Commission directs NERC to develop either a new or modified Reliability Standard that addresses the risks posed by transient devices. For example, the requirements should recognize that transient devices, unlike BES Cyber Assets, are generally portable and frequently connected and disconnected from systems. The Commission expects NERC to consider the following security elements when designing a Reliability Standard for transient devices and removable media: (1) device authorization as it relates to users and locations; (2) software authorization; (3) security patch management; (4) malware prevention; (5) detection controls for unauthorized physical access to a transient device and; (6) processes and procedures for connecting transient devices to systems at different security classification levels (i.e. High, Medium, Low Impact).	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 136	2/13/2015
S- Ref 10901 - We direct NERC to create a definition of communication networks and to develop new or modified Reliability Standards to address the reliability gap discussed above. The definition of communications networks should define what equipment and components should be protected, in light of the statutory inclusion of communication networks for the reliable operation of the Bulk-Power System. The new or modified Reliability Standards should require appropriate and reasonable controls to protect the nonprogrammable aspects of communication networks. The Commission directs NERC to submit these modifications for Commission approval within one year from the effective date of this final rule.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013; 3/20/2014	Order 791; Order 791-A	RM13-5-000	Order 791: Para 150; Order 791-A: Para 22	2/13/2015

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10902 - The Commission directs NERC to modify the VRF assignment for CIP-006-5, Requirement R3 from Lower to Medium, within 90 days of the effective date of this Final Rule.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 184	5/15/2014
S- Ref 10903 - We direct NERC to modify the VRF assignment for CIP-004-5, Requirement R4 from Lower to Medium, within 90 days of the effective date of this Final Rule.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 196	5/15/2014
S- Ref 10904 - For the VSLs that include "identify, assess, and correct" language, we direct NERC to ensure that these VSLs are modified to reflect any revisions to the requirement language in response to our directives. We grant NERC the discretion to decide how best to address these modifications be it through an errata filing to this proceeding or separate filing.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 205	2/13/2015
S- Ref 10905 - With respect to the VSL language for CIP-003-5, Requirements R1 and R2, the Commission notes that the language "as required by R[1 or 2]" and "according to Requirement R[1 or 2]" is redundant and potentially confusing and hereby directs NERC to provide clarification to this language.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 206	5/15/2014
S- Ref 10906 - With respect to the VSL language for CIP-003-5, Requirement R4, the Commission agrees with NERC that basing the VSL language on a timeline is appropriate, but notes that the VSL language does not match the table and analysis documents within Appendix E of the CIP version 5 Petition. After considering NERC's comments, the Commission understands that the correct VSL for this requirement includes timeline gradations. We therefore direct NERC to clarify the VSL language for this requirement to reflect this understanding.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 207	5/15/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10907 - We direct NERC to change the VSL gradation for CIP-004-5, Requirement R4 to be percentage based, instead of using the number of BES Cyber Systems or sites for storing BES Cyber System information. This change will allow for fair treatment for entities that may only have a single BES Cyber system or storage location.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 208	5/15/2014
S- Ref 10908 - With respect to the VSL language for CIP-008-5, Requirement R2, the Commission believes that NERC inserted a typographical error into the petition, creating a gap between 18 months and 19 months in the VSLs. We therefore direct NERC to clarify this language in a further filing.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 209	5/15/2014
S- Ref 10909 - The Commission believes that the 120 day metric is appropriate for these time-based VSL gradations and directs NERC to change the "210 calendar days" language to "120 calendar days" where appropriate.	Version 5 Critical Infrastructure Protection Reliability Standards	11/22/2013	Order 791	RM13-5-000	Para 210	5/15/2014
S- Ref 10910.1 - We agree with a proactive approach to reducing misoperations, i.e., ensuring that a new or modified protection system, when placed in service, is capable of functioning according to its design so that an undetected defect resulting in a misoperation of that protection system does not negatively affect bulk electric system reliability. We encourage and accept NERC's commitment to keep the Commission informed of its efforts concerning this issue. Accordingly, we direct NERC to submit, within one year of issuance of this Final Rule, an informational filing on the status of these efforts, including the development of the guidance report as described in the NERC Comments.	Protection System Maintenance Reliability Standard	12/19/2013	Order 793	RM13-7-000	Para 42	12/19/2014

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S- Ref 10911.1 - We also note that the level of risk associated with the failure to test a given battery is not an appropriate consideration in the context of assigning violation severity levels, but rather, should be considered when assigning a violation risk factor. In this case, Requirement R1 has been assigned a medium violation risk factor, which we accept as properly reflecting NERC's determination that a violation of Requirement R1 could directly affect the electrical state or the capability of the bulk-power system, but is unlikely to lead to bulk power system instability, separation, or cascading failures. We accordingly direct NERC to submit a compliance filing changing the violation severity level for the failure to include station batteries in a time-based maintenance program to "severe."	Protection System Maintenance Reliability Standard	12/19/2013	Order 793	RM13-7-000	Para 66	6/4/2014
S-Ref 10910.2 - the Commission directs the North American Electric Reliability Corporation (NERC), as the Commission-certified Electric Reliability Organization (ERO), to submit for approval one or more Reliability Standards that will require certain registered entities to take steps or demonstrate that they have taken steps to address physical security risks and vulnerabilities related to the reliable operation of the Bulk-Power System... The Commission directs NERC to submit the proposed Reliability Standards to the Commission within 90 days of the date of this order.	Order Directive Filing Of Standards	3/7/2014	Order 795	RD14-6-000	Para 1, 5, 6	5/23/2014
S-Ref 10911.2 - Accordingly, as proposed in the NOPR, we direct NERC to submit a violation severity level that addresses a transmission planner's obligation to provide a technical description of why a model submitted by a generation owner is not usable for Requirement R6 of MOD-026-1 and Requirement R5 of MOD-027-1.	Generator Verification Reliability Standards	3/20/2014	Order 796	RM13-16-000	Para 58	8/29/2014

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10912 - The Commission directs NERC to continue its evaluation of the use of the linear regression methodology based upon experience and data collected following the implementation of BAL-003-1 and to submit a report to the Commission within three months after two years of operating experience once Requirement R1 of BAL-003-1 becomes effective (i.e., 27 months from the effective date of Requirement R1). The report should assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure. Based on this report and actual experience, the Commission may revisit this issue.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 34	Not standards' related (RAPA)
S-Ref 10913 - The Commission adopts the NOPR proposal and directs NERC to submit a report that provides an analysis of the availability of resources for each balancing authority and Frequency Response Sharing Group to meet its Frequency Response Obligation during the first year of implementation. However, NERC indicates in its comments that it needs more than the proposed 15 months to prepare the report based on the time frame for NERC to receive relevant data from applicable entities. Accordingly, we direct NERC to submit this report within 27 months of implementation of Requirement R1. Further, consistent with NERC's representation in its comments, the Commission directs that, upon completion of the required analysis, should the findings indicate that the Frequency Response Obligation was not met, NERC shall provide appropriate recommendations to ensure that frequency response can be maintained at all times within each balancing authority's footprint.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 60	Not standards' related (RAPA)

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10914 - The Commission adopts the proposal in the NOPR and directs NERC to submit the results of the Eastern Interconnection Reliability Assessment Group's light-load case, using actual turbine governor response data. Additionally, the Commission directs NERC to submit a recommendation on whether further actions are warranted no later than 15 months after implementation of the Final Rule. Further, the report should discuss any appropriate changes to the Interconnection Frequency Response Obligation warranted by the study.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 84	Not standards' related (RAPA) 3/20/2015
S-Ref 10915 - We direct NERC to change the violation risk factor for Requirement R1 to "high," as proposed in the NOPR.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 90	8/29/2014
S-Ref 10916 - As proposed in the NOPR, we direct NERC to remove from its violation severity level assignments for Requirement R1 any references to performance of that requirement by other entities.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 95	8/29/2014
S-Ref 10917 - Accordingly, should NERC make changes to Table 1 based upon NERC's Procedure document, the Commission directs NERC to submit an informational notice describing the basis for the changes at least 30 days in advance of the effective date of any such changes.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 100	Ongoing

Table 3: Directives by Commission Order						
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S-Ref 10918 - The Commission directs NERC, pursuant to FPA section 215(d)(5), to remove the term "widespread" from Reliability Standard CIP-014-1 or, alternatively, to propose modifications to the Reliability Standard that address the Commission's concerns. We direct that NERC submit a responsive modification within six months from the effective date of this final rule. The Commission directs NERC to develop a modification to Reliability Standard CIP-014-1 that either removes the term "widespread" from Requirement R1 or, in the alternative, proposes changes that address the Commission's concerns. Further, we direct that NERC submit a responsive modification within six months from the effective date of this final rule. We recognize that certain entities commented on how NERC could modify Reliability Standard CIP-014-1 to address the Commission's stated concerns. However, we conclude that it is appropriate to allow NERC to develop and propose a modification in the first instance. NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	Physical Security Reliability Standard	11/20/2014	Order 802	RM14-15-000	Para 19 and 35	5/15/2015

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10919 - The Commission adopts the proposal to direct NERC to make an informational filing addressing whether Reliability Standard CIP-014-1 provides physical security for all "High Impact" control centers, as that term is defined in Reliability Standard CIP-002-5.1, necessary for the reliable operation of the Bulk-Power System. However, the Commission extends the deadline for that informational filing until two years following the effective date of Reliability Standard CIP-014-1. The Commission adopts the NOPR proposal and directs NERC to submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers. The Commission, however, modifies the NOPR proposal and extends the due date for the informational filing to two years following the effective date of Reliability Standard CIP-014-1. NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	Physical Security Reliability Standard	11/20/2014	Order 802	RM14-15-000	Para 21 and 57	

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10920 - "[W]e direct NERC to obtain, maintain, and make available to the Commission upon request, one year following the effective date of the standard and on an annual basis thereafter, data sufficient to analyze the effectiveness of PRC-005-3, whether it be through NERC's Event Analysis process or other means. Specifically, NERC is to collect relevant information regarding Bulk-Power System events that involve high speed auto-reclosing relays. Such information would include the operations of auto-reclosing relays and their supervisory functionalities (e.g., time delays, synchronism check, voltages, etc.) that caused or exacerbated the events, and any unintended consequences of the events. The Commission encourages NERC and FERC staff to collaborate on the specific data to be collected, which could include, but is not limited to, the approximate distance from the fault and the generation loss associated with the event. Further, the Commission is also interested in knowing if those auto-reclosing relays identified as causing or exacerbating an event operated as designed, and if PRC-005-3 is applicable to the auto-reclosing relays that were involved. We expect NERC to share all appropriate data as needed to evaluate auto-reclosing relay performance, in accordance with our general expectation that NERC will "cooperate with and share all appropriate data and information with Commission staff" as needed "to ensure that the ERO Enterprise and the Commission are both able to effectively perform their duties under section 215 of the FPA."	Protection System Maintenance Reliability Standard	1/22/2015	Order 803	RM14-8-000	Para 25	

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10921 "...direct that, pursuant to section 215(d)(5) of the FPA, NERC develop modifications to PRC-005-3 to include supervisory devices associated with auto-reclosing relay schemes to which the Reliability Standard applies. Further, we clarify that NERC's proposal regarding the scope of supervisory devices is an acceptable approach to satisfy the Commission directive. Specifically, NERC proposed in its NOPR comments, and we find acceptable, that the scope of the supervisory devices to be encompassed in the Reliability Standard are those providing voltage supervision, supervisory inputs associated with selective auto-reclosing, and sync-check relays that are part of a reclosing scheme covered by PRC-005-3."	Protection System Maintenance Reliability Standard	1/22/2015	Order 803	RM14-8-000	Para 31	11/13/2015
S-Ref 10922 - we direct NERC to develop a modification to MOD-031-1 through the standards development process to clarify that planning coordinators and balancing authorities must provide demand and energy data upon request of a Regional Entity, as necessary to support NERC's development of seasonal and long-term reliability assessments.	Order Approving MOD-031-1	2/19/2015	Order 804	Docket No. RM14-12-000	Para 18	11/13/2015
S-Ref 10923 - the Commission directs NERC to consider EEI's concern regarding the compliance obligations of an applicable entity upon receipt of a data request that seeks confidential information in the standard development process when it addresses the directive to clarify that planning coordinators and balancing authorities must provide demand and energy data upon request of a Regional Entity.	Order Approving MOD-031-1	2/19/2015	Order 804	Docket No. RM14-12-000	Para 20	11/13/2015

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10924 - With respect to Portland's concerns regarding WECC's data and the informational filing, the informational filing is intended to identify any issues regarding the adequacy of contingency reserve levels in the Western Interconnection and the impact on other reliability areas such as frequency response. We are satisfied that WECC provided enough representative data to conclude that the new methodology will likely not result in significantly less average contingency reserve in the Western Interconnection. However, for the reasons discussed above, the Commission believes that it is necessary to monitor and assess contingency reserve levels in the Western Interconnection following implementation of the regional Reliability Standard. ...The Commission adopts the NOPR proposal to direct NERC to file an informational filing two years after implementation of the regional Reliability Standard.	Regional Reliability Standard BAL-002-WECC-2 - Contingency Reserve	11/13/2013	Order 789	RM13-13-000	Para 39	Regional
S-Ref 10929 NERC must provide notice to the Commission when a review panel decision is posted. Similar to the process for review of "find, fix and track" compliance posting as well as "compliance exception" postings, the Commission will review such matters and determine within 60 days of receiving notice from NERC whether any formal Commission review is warranted. If the Commission takes no action within 60 days, the Commission will consider the matter closed. We anticipate that Commission review of panel decisions would be a rare occurrence. However, we believe that this opportunity for Commission review provides an important "backstop" to ensure that individual registry matters processed under RBR are decided in a consistent matter with an overall view of providing for the reliability of the bulk electric system.	Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing	3/19/2015	150 FERC ¶ 61,213 Order on RBR	RR-15-4-000	Para 69	7/17/2015

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10930 we direct NERC to modify proposed Section III.D.9, Appendix 5A of the NERC Rules of Procedure to substitute "shall" for "may," to state that "[t]he NERC-led review panel shall also include a review of individual and aggregate system-wide risks…" We direct NERC to address this modification in the compliance filing that NERC must file 60 days after the date of issuance of this order. We anticipate that in many circumstances consideration of aggregate risks will be straightforward.	Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing	3/19/2015	150 FERC ¶ 61,213 Order on RBR	RR-15-4-000	Para 68	7/17/2015
S-Ref 10931 the Commission directs NERC to include Reliability Standard PRC-005 as applicable to underfrequency load shedding-only distribution providers.	Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing	3/19/2015	150 FERC ¶ 61,213 Order on RBR	RR15-4-000	Para 55	7/17/2015

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10932 Accordingly, we deny NERC's proposal to remove the load-serving entity function and direct NERC to submit a compliance filing that addresses the gap in its analysis of the proposed elimination of the load-serving entity function, as discussed above. In particular, NERC should provide an adjusted estimate on the number of load-serving entities that would be deregistered. NERC should provide additional information regarding the peak load of such entities on an individual and balancing authority basis. Further, for the load-serving entities for which NERC anticipates deregistration, NERC must provide specific information regarding the alternative sources of authority which will ensure the continuation of load-serving entity reliability activities by either the deregistered entity or another registered entity. For example, NERC should identify specific tariff provisions and the load-serving entity reliability tasks to which they relate. Likewise, NERC should identify relevant provisions of agreements, market rules or other documents and the load-serving entity reliability tasks to which they relate. If this analysis indicates that gaps remain, NERC should propose alternative means to address identified gaps, such as modifications to specific Reliability Standards or perhaps developing a compliance registry subset similar to the UFLS-only distribution provider category proposed by NERC in its petition.	Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing	3/19/2015	150 FERC ¶ 61,213 Order on RBR	RR15-4-000	Para 41	7/17/2015
S-Ref 10933 submit an informational filing within one year of Commission action "to ensure that there are no unintended consequences to reliability"….	Order on Electric Reliability Organization Risk Based Registration Initiative and Requiring Compliance Filing	3/19/2015	150 FERC ¶ 61,213 Order on RBR	RR15-4-000	Para 2 and 11	1/17/2017

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10925 - Accordingly, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop modifications to COM-001-2, or to develop a new standard, to address our concerns regarding ensuring the adequacy of internal communications capability whenever internal communications could directly affect the reliable operation of the Bulk-Power System.	Communications Reliability Standards	4/16/2015	Order 808	RM14-13-000	Para 41	8/15/2016
S-Ref 10926- (P.2) The Commission also directs NERC to submit an informational filing 90 days after the end of the two-year period following implementation that includes an analysis of data on whether experience with the Balancing Authority ACE Limit in the first two years after approval has seen ACE swings and inadvertent interchange and unscheduled power flows that could cause system operating limit (SOL) and interconnection reliability operating limit (IROL) exceedances, and further directs NERC to revise one definition. (P.36) The Commission adopts the NOPR proposal regarding NERC's submission of an informational filing. We determine that the field trial NERC conducted for Reliability Standard BAL-001-2 raised sufficient concerns regarding unscheduled power flows and inadvertent interchange to warrant NERC's continued monitoring and submission of an informational filing 90 days after the end of the two-year period following implementation, as proposed in the NOPR. Further, we find that the informational filing should encompass both the Western and Eastern Interconnections, as there were concerns about possible increases of SOL/IROL exceedances in both Interconnections.	Real Power Balancing Control Performance Reliability Standard	4/16/2015	Order 810	RM14-10-000	Para 2 Para 36	

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10927 - Accordingly, the Commission directs NERC to revise the definition of Reporting ACE to include the "Lmax" upper payback limit and the bounds of that upper payback limit prior to the effective date of Reliability Standard BAL-001-1.	Real Power Balancing Control Performance Reliability Standard	4/16/2015	Order 810	RM14-10-000	Para 43	4/20/2016
S-Ref 10928 - we direct NERC to submit a compliance filing within 60 days of issuance of this order that revises the proposed "medium" VRF designations to "high." P1: The Commission, however, directs NERC to submit a compliance filing, within 60 days of the issuance of this order, to address certain concerns regarding the VRF designations for Requirements R1 through R6, as described below.	Order Approving Reliability Standard	5/13/2015	151 FERC ¶ 61,129 Order Approving PRC-004-3	RD14-14-000	Para 1 Para 20	7/7/2015
S-Ref 10934 direct NERC to submit a compliance filing within 60 days of the date of this order retaining the existing language in the Hearings section	ORDER ON REVISIONS TO COMPLIANCE AND CERTIFICATION COMMITTEE CHARTER	8/21/2015	152 FERC ¶ 61,142	RR15-11-000	Para 9	11/17/2015
S-Ref 10935 we direct NERC to study and report to the Commission, within 15 months from the date of this order, the extent to which the next-day studies by a representative sample of the affected transmission operators and balancing authorities match or differ from their real-time results and, if there are any significant differences, whether those differences are attributable to the changes authorized here. In performing this analysis, NERC may choose to compare these results to results for the same entities before implementation of these changes, or to results for entities not affected by these changes, or both, if NERC deems it appropriate.	Order on Compliance Filing	10/15/2015	153 FERC ¶ 61,024	RR15-4-001	Para 25	1/17/2017

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10936 we direct NERC to modify the Pro Forma Delegation Agreement and specific Delegation Agreements with each Regional Entity by removing the automatic renewal provisions, such that the Delegation Agreements are subject to our re-evaluation and re-approval following the initial term, scheduled to end on December 31, 2020.	ORDER CONDITIONALLY APPROVING REVISED PRO FORMA DELEGATION AGREEMENT AND REVISED DELEGATION AGREEMENTS WITH REGIONAL ENTITIES	11/2/2015	153 FERC ¶ 61,135	RR15-12-001	Para 59	12/8/2015
S-Ref 10937 we direct NERC to submit a compliance filing within 120 days of the date of this order, revising section 12 of the Pro Forma Delegation Agreement by removing the proposed automatic renewal provisions and by re-inserting the audit provisions in section 12(b) that NERC proposes to eliminate. In this filing, NERC must also replace the references in section 12(b) to audits "pursuant to subsection 6(i)" with a reference to audits "pursuant to the audit requirements of the NERC Rules of Procedure" because the Commission is approving the deletion of section 6(i) in the Delegation Agreements.	ORDER CONDITIONALLY APPROVING REVISED PRO FORMA DELEGATION AGREEMENT AND REVISED DELEGATION AGREEMENTS WITH REGIONAL ENTITIES	11/2/2015	153 FERC ¶ 61,135	RR15-12-001	Para 62	12/8/2015
S-Ref 10938 we direct NERC to include in its compliance filing a revision to proposed section 3(b) of the Delegation Agreements to include a provision requiring NERC to maintain on its public website the currently effective versions of all of the Regional Entities' bylaws and regional standard development procedures. We also reiterate that all Regional Entity Rules, such as the Regional Entity bylaws and regional standard development procedures, must be filed with and approved by the Commission before they become effective.	ORDER CONDITIONALLY APPROVING REVISED PRO FORMA DELEGATION AGREEMENT AND REVISED DELEGATION AGREEMENTS WITH REGIONAL ENTITIES	11/2/2015	153 FERC ¶ 61,135	RR15-12-001	Para 70	12/8/2015

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10939 we direct NERC to clarify in its compliance filing, to be filed within 120 days of the date of this order, the meaning of other "guidance that NERC may from time to time develop," and that its guidance on reporting to the Commission instances of noncompliance of Reliability Standards and their disposition must be filed with the Commission for approval before it becomes effective.	ORDER CONDITIONALLY APPROVING REVISED PRO FORMA DELEGATION AGREEMENT AND REVISED DELEGATION AGREEMENTS WITH REGIONAL ENTITIES	11/2/2015	153 FERC ¶ 61,135	RR15-12-001	Para 73	12/8/2015
S-Ref 10940 we direct NERC to submit a compliance filing within 120 days of the date of this order to include language in section 15 of the Delegation Agreements stating that the provisions of section 1500 of the NERC Rules of Procedure control when a conflict between it and the Delegation Agreements may arise.	ORDER CONDITIONALLY APPROVING REVISED PRO FORMA DELEGATION AGREEMENT AND REVISED DELEGATION AGREEMENTS WITH REGIONAL ENTITIES	11/2/2015	153 FERC ¶ 61,135	RR15-12-001	Para 79	12/8/2015
S-Ref 10941 with respect to WECC's 2017 business plan and budget, we direct WECC to include information on any further payments made and to be made for penalties imposed on WECC.	ORDER ON 2016 BUSINESS PLANS AND BUDGETS	11/2/2015	153 FERC ¶ 61,134	RR15-16-001	Para 54	8/23/2016
S-Ref 10942 when this issue is considered in Project 2015-19, the specific regional difference of WECC's 1,000 MW threshold in IROLs should be evaluated in light of the Commission's directive in Order No. 802 (approving Reliability Standard CIP-014) to eliminate or clarify the "widespread" qualifier on "instability" as well as our statement in the Remand NOPR that "operators do not always foresee the consequences of exceeding such SOLs and thus cannot be sure of preventing harm to reliability."	Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards	11/19/2015	Order No. 817	RM15-16-000	Para 27	

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10943 we direct NERC to revise Reliability Standard TOP-001-3, Requirement R10 to require real-time monitoring of non-BES facilities. We believe this is best accomplished by adopting language similar to Reliability Standard IRO-002-4, Requirement R3, which requires reliability coordinators to monitor non-bulk electric system facilities to the extent necessary.	Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards	11/19/2015	Order No. 817	RM15-16-000	Para 35	3/6/2017
S-Ref 10944 we direct NERC to modify Reliability Standards TOP-001-3, Requirements R19 and R20 to include the requirement that the data exchange capabilities of the transmission operators and balancing authorities require redundancy and diverse routing.	Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards	11/19/2015	Order No. 817	RM15-16-000	Para 47	3/6/2017
S-Ref 10945 we direct NERC to clarify that “redundant infrastructure” for system monitoring in Reliability Standards IRO-002-4, Requirement R4 is equivalent to redundant and diversely routed data exchange capabilities.	Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards	11/19/2015	Order No. 817	RM15-16-000	Para 47	3/6/2017
S-Ref 10946 we direct NERC to develop a modification to the TOP and IRO standards that addresses a data exchange capability testing framework for the data exchange capabilities used in the primary control centers to test the alternate or less frequently used data exchange capabilities of the reliability coordinator, transmission operator and balancing authority.	Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards	11/19/2015	Order No. 817	RM15-16-000	Para 51	3/6/2017

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10947 we direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission's concerns, the proposed modifications should be designed to effectively address the risks posed by transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards.	Revised Critical Infrastructure Protection Reliability Standards	1/21/2016	Order No. 822	RM15-14-000	Para 32	
S-Ref 10948 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).	Revised Critical Infrastructure Protection Reliability Standards	1/21/2016	Order No. 822	RM15-14-000	Para 53	
S-Ref 10949 we direct NERC to conduct a study that assesses the effectiveness of the CIP version 5 remote access controls, the risks posed by remote access-related threats and vulnerabilities, and appropriate mitigating controls for any identified risks. NERC should consult with Commission staff to determine the general contents of the directed report. We direct NERC to submit a report on the above outlined study within one year of the implementation of the CIP version 5 Standards for High and Medium Impact BES Cyber Systems.	Revised Critical Infrastructure Protection Reliability Standards	1/21/2016	Order No. 822	RM15-14-000	Para 64	

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-Ref 10950 we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.	Revised Critical Infrastructure Protection Reliability Standards	1/21/2016	Order No. 822	RM15-14-000	Para 73	
S- Ref 10951- "[W]e direct NERC to develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations.2 The new or modified Reliability Standard should address the following security objectives, discussed in detail below: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls. In making this directive, the Commission does not require NERC to impose any specific controls, nor does the Commission require NERC to propose "one-size-fits-all" requirements. The new or modified Reliability Standard should instead require responsible entities to develop a plan to meet the four objectives, or some equally efficient and effective means to meet these objectives, while providing flexibility to responsible entities as to how to meet those objectives. 14 Galloway Technical Conference Comments at 1 ("…ISO-NE supports the Commission's proposal to direct NERC to develop requirements relating to supply chain risk management. We believe that the risks to the	Revised Critical Infrastructure Protection Reliability Standards	7/2/2016	Order 829	RM15-14-002	Para 14 and Footnote 14	

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Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
reliability of the Bulk Electric System that result from compromised third-party software are real, significant and largely unaddressed by existing reliability standards. While many public utilities are already assessing these risks and asking vendors to address them, these one-off efforts are far less likely to be effective than an industry-wide reliability standard.").						
S-ref 10952P44: "[T]he Commission, as proposed in the NOPR, directs NERC to develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data." P47: "Without prejudging how NERC proposes to address the Commission's directive, NERC's response to this directive should satisfy the NOPR's concern that reliance on spatially-averaged data alone does not address localized peaks that could potentially affect the reliable operation of the Bulk-Power System." P48: "NERC could revise [the standard] to apply a higher reference peak geoelectric field amplitude value to assess the impact of localized hot spots on the Bulk-Power System, as suggested by the Trade Associations." P49: "Consistent with Order No. 779, the Commission does not specify a particular reference peak geoelectric field amplitude value that should be applied to hot spots given present uncertainties."	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 44-Para 49	

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-ref 10953- P65: "Consistent with our determination above regarding the reference peak geoelectric field amplitude value, the Commission directs NERC to revise Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments."	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 65	
Standard TPL-007-1 to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need. The NERC standard drafting team should address the criteria for collecting GIC monitoring and magnetometer data discussed below and provide registered entities with sufficient guidance in terms of defining the data that must be collected, and NERC should propose in the GMD research work plan how it will determine and report on the degree to which industry is following that guidance." Magnetometer Requirements P90: "In developing a requirement regarding the collection of magnetometer data, NERC should consider the following criteria discussed at the March 1, 2016 Technical Conference: (1) the data is sampled at a cadence of at least 10-seconds or faster; (2) the data comes from magnetometers that are physically close to GIC monitors; (3) the data comes from magnetometers that are not near sources of magnetic interference (e.g., roads and local distribution networks); and (4) data is	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 65, Paras 90-92	

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
collected from magnetometers spread across wide latitudes and longitudes and from diverse physiographic regions." GIC Requirements P 91: "Each responsible entity that is a transmission owner should be required to collect necessary GIC monitoring data. However, a transmission owner should be able to apply for an exemption from the GIC monitoring data collection requirement if it demonstrates that little or no value would be added to planning and operations. In developing a requirement regarding the collection of GIC monitoring data, NERC should consider the following criteria discussed at the March 1, 2016 Technical Conference: (1) the GIC data is from areas found to have high GIC based on system studies; (2) the GIC data comes from sensitive installations and key parts of the transmission grid; and (3) the data comes from GIC monitors that are not situated near transportation systems using direct current (e.g., subways or light rail." *** P 91: GIC monitoring and magnetometer locations should also be revisited after GIC system models are run with improved ground conductivity models. NERC may also propose to incorporate the GIC monitoring and magnetometer data collection requirements in a different Reliability Standard (e.g., real-time reliability monitoring and analysis capabilities as part of the TOP Reliability Standards).						

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
P 92: "[T]he Commission determines that requiring responsible entities to collect necessary GIC monitoring and magnetometer data, rather than install GIC monitors and magnetometers, affords greater flexibility while obtaining significant benefits."						
S-ref 10955 P 101: "The Commission directs NERC to modify Reliability Standard TPL-007-1 to include a deadline of one year from the completion of the GMD Vulnerability Assessments to complete the development of corrective action plans." P 102: "The Commission also directs NERC to modify Reliability Standard TPL-007-1 to include a two-year deadline after the development of the corrective action plan to complete the implementation of non-hardware mitigation and four-year deadline to complete hardware mitigation…" "The Commission agrees that NERC should consider extensions of time on a case-by-case basis.	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Paras 101-102	
S-ref 10956 P 77: "First, the Commission adopts the NOPR proposal and directs NERC to submit a GMD research work plan and, subsequently, informational filings that address the GMD-related research areas identified in the NOPR, additional research tasks identified in this Final Rule… and, in NERC's discretion, any GMD-related research areas generally that may impact the development of new or modified GMD Reliability Standards."	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 77 and Para 81	

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
"The research required by this directive should be informed by ongoing GMD-related research efforts of entities such as USGS, [NOAA], [NASA], [DOE], academic and other publicly available contributors, including work performed for the National Space Weather Action Plan." P 81: "[W]e do not set specific deadlines for completion of the research; we only require NERC to submit the GMD research work plan within six months of the effective date of a final rule. The GMD research work plan, in turn, should include target dates for the completion of research topics and the reporting of findings to the Commission. The Commission intends to notice and invite comment on the GMD research work plan. An extension of time to submit the GMD research work plan may be available if six months proves to be insufficient. In addition, given the uncertainties commonly associated with complex research projects, the Commission will be flexible regarding changes to the tasks and target dates established in the GMD research work plan."						
S-ref 10957 COLLECT EXISTING AND NEW GIC/MAGNETOMETER DATA AND MAKE IT PUBLICLY AVAILABLE P 88: "[T]he Commission directs NERC, pursuant to Section 1600 of the NERC Rules of Procedure, to collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013, including	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 88, Paras 93-95	

Table 3: Directives by Commission Order						
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both data existing as of the date of this order and new data going forward, and to make that information available." FN118: "The Commission's directives to collect and make available GIC monitoring and magnetometer data do not apply to non-U.S. responsible entities or Alaska and Hawaii. P 93: "We also direct NERC, pursuant to Sections 1500 and 1600 of the NERC Rules of Procedure, to collect and make GIC monitoring and magnetometer data available." FN 112: "If GIC monitoring and magnetometer data is already publicly available (e.g., from a government entity or university), NERC need not duplicate these efforts. P 94: "Based on the record in this proceeding, we believe that GIC and magnetometer data typically should not be designated as Confidential Information under the NERC Rules of Procedure." 95: "Notwithstanding our findings here, to the extent any entity seeks confidential treatment of the data it provides to NERC, the burden rests on that entity to justify the confidential treatment. Exceptions are possible if the providing entity obtains from NERC, at the time it submits data to NERC, a determination that GIC or magnetometer data qualify as Confidential Information. Entities denied access to GIC and magnetometer data by NERC or providers denied Confidential Information treatment of GIC and magnetometer data may appeal NERCs decision to the Commission."						

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
s-ref 10959- "The Commission amends its regulations, pursuant to section 215 of the Federal Power Act (FPA), to require the North American Electric Reliability Corporation (NERC) to provide the Commission, and Commission staff, with access, on a non-public and ongoing basis, to certain databases compiled and maintained by NERC. The amended regulation applies to the following NERC databases: (1) the Transmission Availability Data System (TADS), (2) the Generating Availability Data System (GADS), and (3) the protection system misoperations database. Access to these databases, which will be limited to data regarding U.S. facilities provided to NERC on a mandatory basis, will provide the Commission with information necessary to determine the need for new or modified Reliability Standards and to better understand NERC's periodic reliability and adequacy assessments."	Availability of Certain North American Electric Reliability Corporation Databases to the Commission	6/16/2016	Order 824	RM15-25-000	Entire Order	
S-ref10958- P2: "The Commission, as discussed below, directs NERC to submit a compliance filing within 60 days of the date of this order to modify the violation risk factor designations for Requirement R1 of Reliability Standard IRO-018-1 and Requirements R1 and R2 of Reliability Standard TOP-010-1 to "high."" P18 -"Accordingly, we direct NERC to raise these violation risk factor designations to "high."	Order Approving Reliability Standards	9/22/2016	156 FERC ¶ 61,207	RD16-6-000	P2 and P18	11/7/2016

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
S-ref10953- P23: "[W]e direct NERC to develop modifications to Reliability Standard BAL-002-2 to address our concerns, discussed below, regarding the 15-minute ACE recovery period set forth in Requirement R1." P37: "[W]e direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require balancing authorities or reserve sharing groups: (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."	Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard	1/19/2017	Order 835	RM16-7	Para 23 and Para 37	
S-ref10954- P23: "We also direct NERC to collect and report on data pertaining to the occurrence of Balancing Contingency Events that trigger resets of the 90-minute Contingency Reserve Restoration Period under Requirement R3." s-ref10954- P46: "the Commission directs NERC to collect and report data pertaining to: (1) additional megawatt losses following Reportable Balancing Contingency Events during the Contingency Reserve Restoration Period; and (2) the time periods for contingency reserve restoration under Requirement R3 and the number of resets of the 90-minute restoration period, and submit a report to the Commission two years following the first day of implementation of Requirement R3. After NERC reports on the data in a compliance filing, the	Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard	1/19/2017	Order 835	RM16-7	Para 23 and Para 46	

Table 3: Directives by Commission Order						
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Actual NERC Filing to FERC Date**
Commission will consider what further action, if any, to take."						
S-ref 10955-P23: "We further direct NERC to study and submit a report to the Commission with findings regarding reliability risks associated with most severe single contingency exceedances that do not result in energy emergencies."	Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard	1/19/2017	Order 835	RM16-7	Para 23	
S-ref 10956- P68: "[W]e direct NERC to assign a "high" violation risk factor to Reliability Standard BAL-002-2, Requirements R1 and R2."	Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard	1/19/2017	Order 835	RM16-7	Para 68	

Appendix C – Remaining Directives to be Addressed

Remaining Directives

Below is a list of the remaining directives as of this filing.

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S- Ref 10101 - Collect outage data for transmission outages of lines that cross both federal and non-federal lands, analyze it, and use the results to develop a standard that would apply to both federal and non-federal lands. NERC should gather and analyze the necessary data regarding vegetation management issues on public lands. If NERC's analysis indicates that there are issues that should be addressed, NERC should propose a means to address the concern, for example by issuing an alert, or propose other appropriate action."	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007; 3/21/2013	Order 693, 777	RM06-16-000; RM12-4-000	Order 693 Para 732; Order 777 Para 129, 130	2010-07.1 FAC-003-2 RAPA	Vegetation Management	Not standards related (RAPA)
S-Ref 10917 - Accordingly, should NERC make changes to Table 1 based upon NERC's Procedure document, the Commission directs NERC to submit an informational notice describing the basis for the changes at least 30 days in advance of the effective date of any such changes.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 100		Frequency Response	Ongoing

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-Ref 10912 - The Commission directs NERC to continue its evaluation of the use of the linear regression methodology based upon experience and data collected following the implementation of BAL-003-1 and to submit a report to the Commission within three months after two years of operating experience once Requirement R1 of BAL-003-1 becomes effective (i.e., 27 months from the effective date of Requirement R1). The report should assess the accuracy of the linear regression methodology compared to the median methodology for purposes of determining Frequency Response Measure. Based on this report and actual experience, the Commission may revisit this issue.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 34	2007-12.1 RAPA		Not standards related (RAPA)
S-Ref 10913 - The Commission adopts the NOPR proposal and directs NERC to submit a report that provides an analysis of the availability of resources for each balancing authority and Frequency Response Sharing Group to meet its Frequency Response Obligation during the first year of implementation. However, NERC indicates in its comments that it needs more than the proposed 15 months to prepare the report based on the time frame for NERC to receive relevant data from applicable entities. Accordingly, we direct NERC to submit this report within 27 months of implementation of Requirement R1. Further, consistent with NERC's representation in its comments, the Commission directs that, upon completion of the required analysis, should the findings indicate that the Frequency Response Obligation was not met, NERC shall provide appropriate recommendations to ensure that frequency response can be maintained at all times within each balancing authority's footprint.	Frequency Response and Frequency Bias Setting Reliability Standard	1/16/2014	Order 794	RM13-11-000	Para 60	2007-12.1 RAPA		Not standards related (RAPA)

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S- Ref 10894 - Direct 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.	Transmission Planning Reliability Standards	10/17/2013	Order 786	RM12-1-000 and RM13-9-000	Para 40	2015-10	Single Points of Failure	
S- Ref 10896 - Directs NERC to consider a similar spare equipment strategy for stability analysis upon the next review cycle of Reliability Standard TPL-001-4.	Transmission Planning Reliability Standards	10/17/2013	Order 786	RM12-1-000 and RM13-9-000	Para 89	2015-10	Single Points of Failure	
S- Ref 10893 - Direct NERC to report on the use of footnote 12 including the use and effectiveness of the local regulatory review and NERC review. This report is important because it will provide an analysis of the use of footnote 12, including but not limited to information on the duration, frequency and magnitude of planned non-consequential load loss, and typical (and if significant, atypical) scenarios where entities plan for non-consequential load loss.	Transmission Planning Reliability Standards	10/17/2013	Order 786	RM12-1-000 and RM13-9-000	Para 30	RAPA	TBD	RAPA Project
S- Ref 10023 - In the five-year review cycle of the standard, perform research that would provide a technical basis for the present or any alternative approach that is more effective and helps reduce inadvertent interchange. (BAL-004)	Mandatory Reliability Standards for the Bulk-Power System	3/16/2007	Order 693	RM06-16-000	Para 385	2010-14.2.2	Phase 2 of Balancing Authority Reliability-based Control: Time Error, AGC, and Inadvertent	RAPA Project

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S- Ref 10871 - …a. "As discussed below, we also direct NERC to develop a means to assure that IROLs are communicated to transmission owners." (P 6) "NERC must establish a clearly defined communication structure to assure that IROLs and changes to IROL status are timely communicated to transmission owners. Left to NERC how to accomplish this objective. Commission identifies modification of FAC-014 as a vehicle that would meet the objective." (P 41) "NERC should inform the Commission of when it has developed means for communication of IROLs to transmission owners to help ensure that they receive notice of each of their applicable lines before the standard becomes effective as to those lines." (P 42)	Revisions to Reliability Standard for Transmission Vegetation Management	3/21/2013	Order 777	RM12-4-000	Para 6, 41, 42	2015-09 FAC-014 Enhanced periodic review	Vegetation Management	Not standards related (RAPA)

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-Ref 10924 - With respect to Portland's concerns regarding WECC's data and the informational filing, the informational filing is intended to identify any issues regarding the adequacy of contingency reserve levels in the Western Interconnection and the impact on other reliability areas such as frequency response. We are satisfied that WECC provided enough representative data to conclude that the new methodology will likely not result in significantly less average contingency reserve in the Western Interconnection. However, for the reasons discussed above, the Commission believes that it is necessary to monitor and assess contingency reserve levels in the Western Interconnection following implementation of the regional Reliability Standard. ...The Commission adopts the NOPR proposal to direct NERC to file an informational filing two years after implementation of the regional Reliability Standard.	Regional Reliability Standard BAL-002-WECC-2 - Contingency Reserve	11/13/2013	Order 789	RM13-13-000	Para 39	BAL-002-WECC-2	Regional BAL	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-Ref 10919 - The Commission adopts the proposal to direct NERC to make an informational filing addressing whether Reliability Standard CIP-014-1 provides physical security for all "High Impact" control centers, as that term is defined in Reliability Standard CIP-002-5.1, necessary for the reliable operation of the Bulk-Power System. However, the Commission extends the deadline for that informational filing until two years following the effective date of Reliability Standard CIP-014-1. The Commission adopts the NOPR proposal and directs NERC to submit an informational filing that addresses whether there is a need for consistent treatment of "High Impact" control centers for cybersecurity and physical security purposes through the development of Reliability Standards that afford physical protection to all "High Impact" control centers. The Commission, however, modifies the NOPR proposal and extends the due date for the informational filing to two years following the effective date of Reliability Standard CIP-014-1. NERC indicated that NERC staff will submit to the NERC Board of Trustees a report three months following implementation of Requirements R1, R2 and R3 concerning the scope of facilities identified as critical, including the number of facilities identified as critical and their defining characteristics. NERC also committed to sending this report to Commission staff.	Physical Security Reliability Standard	11/20/2014	Order 802	RM14-15-000	Para 21 and 57	2014-04	Physical Security	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S- Ref 10820 - The Commission believe that NERC should register demand side aggregators if the loss of their load shedding capability, for reasons such as a cyber incident, would affect the reliability or operability of the Bulk-Power System.	Mandatory Reliability Standards for Critical Infrastructure Protection	1/18/2008	Order 706	RM06-22-000	Para 051	NERC Registration	For Directives assigned to Compliance	Regional

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-Ref 10920 - "[W]e direct NERC to obtain, maintain, and make available to the Commission upon request, one year following the effective date of the standard and on an annual basis thereafter, data sufficient to analyze the effectiveness of PRC-005-3, whether it be through NERC's Event Analysis process or other means. Specifically, NERC is to collect relevant information regarding Bulk-Power System events that involve high speed auto-reclosing relays. Such information would include the operations of auto-reclosing relays and their supervisory functionalities (e.g., time delays, synchronism check, voltages, etc.) that caused or exacerbated the events, and any unintended consequences of the events. The Commission encourages NERC and FERC staff to collaborate on the specific data to be collected, which could include, but is not limited to, the approximate distance from the fault and the generation loss associated with the event. Further, the Commission is also interested in knowing if those auto-reclosing relays identified as causing or exacerbating an event operated as designed, and if PRC-005-3 is applicable to the auto-reclosing relays that were involved. We expect NERC to share all appropriate data as needed to evaluate auto-reclosing relay performance, in accordance with our general expectation that NERC will "cooperate with and share all appropriate data and information with Commission staff" as needed "to ensure that the ERO Enterprise and the Commission are both able to effectively perform their duties under section 215 of the FPA."	Protection System Maintenance Reliability Standard	1/22/2015	Order 803	RM14-8-000	Para 25	2007-17.4	Protection System Maintenance and Testing PRC-005-3 directives	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S- Ref 10752 - The Commission directs RFC to add time horizons to the two main requirements when RFC reviews BAL-502-RFC-02 at the scheduled five-year review.	Final Rule Approving Planning Resource Adequacy Assessment Standard BAL-502-RFC-02	3/17/2011	Order 747	RM10-10-000	Para 53	Regional	For directives assigned to regions	
S- Ref 10753 - Consider, at the time of its five-year review, whether to add a requirement to BAL-502-RFC-02 that would require Planning Coordinators to identify any gap between the needed amount of planning reserves defined in Requirement R1.1 and the planning reserves determined from the resource adequacy analysis.	Final Rule Approving Planning Resource Adequacy Assessment Standard BAL-502-RFC-02	3/17/2011	Order 747	RM10-10-000	Para 65	Regional	For directives assigned to regions	
S-Ref 10947 we direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission's concerns, the proposed modifications should be designed to effectively address the risks posed by transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards.	Revised Critical Infrastructure Protection Reliability Standards	1/21/2016	Order No. 822	RM15-14-000	Para 32	2016-02	Modifications to CIP Standards	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-Ref 10948 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).	Revised Critical Infrastructure Protection Reliability Standards	1/21/2016	Order No. 822	RM15-14-000	Para 53	2016-02	Modifications to CIP Standards	
S-Ref 10949 we direct NERC to conduct a study that assesses the effectiveness of the CIP version 5 remote access controls, the risks posed by remote access-related threats and vulnerabilities, and appropriate mitigating controls for any identified risks. NERC should consult with Commission staff to determine the general contents of the directed report. We direct NERC to submit a report on the above outlined study within one year of the implementation of the CIP version 5 Standards for High and Medium Impact BES Cyber Systems.	Revised Critical Infrastructure Protection Reliability Standards	1/21/2016	Order No. 822	RM15-14-000	Para 64	2016-02	Modifications to CIP Standards	
S-Ref 10950 we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule. We agree with NERC and other commenters that a suitable means to address our concern is to modify the Low Impact External Routable Connectivity definition consistent with the commentary in the Guidelines and Technical Basis section of CIP-003-6.	Revised Critical Infrastructure Protection Reliability Standards	1/21/2016	Order No. 822	RM15-14-000	Para 73	2016-02	Modifications to CIP Standards	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S- Ref 10951- "[W]e direct NERC to develop a forward-looking, objective-based Reliability Standard to require each affected entity to develop and implement a plan that includes security controls for supply chain management for industrial control system hardware, software, and services associated with bulk electric system operations.2 The new or modified Reliability Standard should address the following security objectives, discussed in detail below: (1) software integrity and authenticity; (2) vendor remote access; (3) information system planning; and (4) vendor risk management and procurement controls. In making this directive, the Commission does not require NERC to impose any specific controls, nor does the Commission require NERC to propose "one-size-fits-all" requirements. The new or modified Reliability Standard should instead require responsible entities to develop a plan to meet the four objectives, or some equally efficient and effective means to meet these objectives, while providing flexibility to responsible entities as to how to meet those objectives. 14 Galloway Technical Conference Comments at 1 ("…ISO-NE supports the Commission's proposal to direct NERC to develop requirements relating to supply chain risk management. We believe that the risks to the reliability of the Bulk Electric System that result from compromised third-party software are real, significant and largely unaddressed by existing reliability standards. While many public utilities are already assessing these risks and asking vendors to address them, these one-off efforts are far less likely to be effective than an industry-wide reliability standard.").	Revised Critical Infrastructure Protection Reliability Standards	7/2/2016	Order 829	RM15-14-002	Para 14 and Footnote 14	2016-03	Cyber Security Supply Chain Risk Management	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-ref 10952P44: "[T]he Commission, as proposed in the NOPR, directs NERC to develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude component is not based solely on spatially-averaged data." P47: "Without prejudging how NERC proposes to address the Commission's directive, NERC's response to this directive should satisfy the NOPR's concern that reliance on spatially-averaged data alone does not address localized peaks that could potentially affect the reliable operation of the Bulk-Power System." P48: "NERC could revise [the standard] to apply a higher reference peak geoelectric field amplitude value to assess the impact of localized hot spots on the Bulk-Power System, as suggested by the Trade Associations." P49: "Consistent with Order No. 779, the Commission does not specify a particular reference peak geoelectric field amplitude value that should be applied to hot spots given present uncertainties	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 44-Para 49	2013-03	Geomagnetic Disturbance Mitigation	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-ref 10953- P65: "Consistent with our determination above regarding the reference peak geoelectric field amplitude value, the Commission directs NERC to revise Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments."	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 65	2013-03	Geomagnetic Disturbance Mitigation	
Standard TPL-007-1 to require responsible entities to collect GIC monitoring and magnetometer data as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need. The NERC standard drafting team should address the criteria for collecting GIC monitoring and magnetometer data discussed below and provide registered entities with sufficient guidance in terms of defining the data that must be collected, and NERC should propose in the GMD research work plan how it will determine and report on the degree to which industry is following that guidance." Magnetometer Requirements P90: "In developing a requirement regarding the collection of magnetometer data, NERC should consider the following criteria discussed at the March 1, 2016 Technical Conference: (1) the data is sampled at a cadence of at least 10-seconds or faster; (2) the data comes from magnetometers that are physically close to GIC monitors; (3) the data comes from magnetometers that are not near sources of magnetic interference (e.g., roads and local distribution networks); and (4) data is collected	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 65, Paras 90-92	2013-03	Geomagnetic Disturbance Mitigation	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
from magnetometers spread across wide latitudes and longitudes and from diverse physiographic regions." GIC Requirements P 91: "Each responsible entity that is a transmission owner should be required to collect necessary GIC monitoring data. However, a transmission owner should be able to apply for an exemption from the GIC monitoring data collection requirement if it demonstrates that little or no value would be added to planning and operations. In developing a requirement regarding the collection of GIC monitoring data, NERC should consider the following criteria discussed at the March 1, 2016 Technical Conference: (1) the GIC data is from areas found to have high GIC based on system studies; (2) the GIC data comes from sensitive installations and key parts of the transmission grid; and (3) the data comes from GIC monitors that are not situated near transportation systems using direct current (e.g., subways or light rail." *** P 91: GIC monitoring and magnetometer locations should also be revisited after GIC system models are run with improved ground conductivity models. NERC may also propose to incorporate the GIC monitoring and magnetometer data collection requirements in a different Reliability Standard (e.g., real-time reliability monitoring and analysis capabilities as part of the TOP Reliability Standards). P 92: "[T]he Commission determines that requiring responsible entities to collect necessary GIC								

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
monitoring and magnetometer data, rather than install GIC monitors and magnetometers, affords greater flexibility while obtaining significant benefits."								
S-ref 10955 P 101: "The Commission directs NERC to modify Reliability Standard TPL-007-1 to include a deadline of one year from the completion of the GMD Vulnerability Assessments to complete the development of corrective action plans." P 102: "The Commission also directs NERC to modify Reliability Standard TPL-007-1 to include a two-year deadline after the development of the corrective action plan to complete the implementation of non-hardware mitigation and four-year deadline to complete hardware mitigation…" "The Commission agrees that NERC should consider extensions of time on a case-by-case basis.	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Paras 101-102	2013-03	Geomagnetic Disturbance Mitigation	
S-ref 10956 P 77: "First, the Commission adopts the NOPR proposal and directs NERC to submit a GMD research work plan and, subsequently, informational filings that address the GMD-related research areas identified in the NOPR, additional research tasks identified in this Final Rule… and, in NERC's discretion, any GMD-related research areas generally that may impact the development of new or modified GMD Reliability Standards." "The research required by this directive should be informed by ongoing GMD-related research efforts	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 77 and Para 81	2013-03	Geomagnetic Disturbance Mitigation	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
of entities such as USGS, [NOAA], [NASA], [DOE], academic and other publicly available contributors, including work performed for the National Space Weather Action Plan." P 81: "[W]e do not set specific deadlines for completion of the research; we only require NERC to submit the GMD research work plan within six months of the effective date of a final rule. The GMD research work plan, in turn, should include target dates for the completion of research topics and the reporting of findings to the Commission. The Commission intends to notice and invite comment on the GMD research work plan. An extension of time to submit the GMD research work plan may be available if six months proves to be insufficient. In addition, given the uncertainties commonly associated with complex research projects, the Commission will be flexible regarding changes to the tasks and target dates established in the GMD research work plan."								
S-ref 10957 COLLECT EXISTING AND NEW GIC/MAGNETOMETER DATA AND MAKE IT PUBLICLY AVAILABLE P 88: "[T]he Commission directs NERC, pursuant to Section 1600 of the NERC Rules of Procedure, to collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013, including both data existing as of the date of this order and new data going forward, and to make that information available."	Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Event	9/22/2016	Order 830	RM15-11-000	Para 88, Paras 93-95	2013-03	Geomagnetic Disturbance Mitigation	

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
FN118: "The Commission's directives to collect and make available GIC monitoring and magnetometer data do not apply to non-U.S. responsible entities or Alaska and Hawaii. P 93: "We also direct NERC, pursuant to Sections 1500 and 1600 of the NERC Rules of Procedure, to collect and make GIC monitoring and magnetometer data available." FN 112: "If GIC monitoring and magnetometer data is already publicly available (e.g., from a government entity or university), NERC need not duplicate these efforts. P 94: "Based on the record in this proceeding, we believe that GIC and magnetometer data typically should not be designated as Confidential Information under the NERC Rules of Procedure." 95: "Notwithstanding our findings here, to the extent any entity seeks confidential treatment of the data it provides to NERC, the burden rests on that entity to justify the confidential treatment. Exceptions are possible if the providing entity obtains from NERC, at the time it submits data to NERC, a determination that GIC or magnetometer data qualify as Confidential Information. Entities denied access to GIC and magnetometer data by NERC or providers denied Confidential Information treatment of GIC and magnetometer data may appeal NERCs decision to the Commission."								

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-ref10953- P23: "[W]e direct NERC to develop modifications to Reliability Standard BAL-002-2 to address our concerns, discussed below, regarding the 15-minute ACE recovery period set forth in Requirement R1." P37: "[W]e direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require balancing authorities or reserve sharing groups: (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."	Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard	1/19/2017	Order 835	RM16-7	Para 23 and Para 37			
S-ref10954- P23: "We also direct NERC to collect and report on data pertaining to the occurrence of Balancing Contingency Events that trigger resets of the 90-minute Contingency Reserve Restoration Period under Requirement R3." s-ref10954- P46: "the Commission directs NERC to collect and report data pertaining to: (1) additional megawatt losses following Reportable Balancing Contingency Events during the Contingency Reserve Restoration Period; and (2) the time periods for contingency reserve restoration under Requirement R3 and the number of resets of the 90-minute restoration period, and submit a report to the Commission two years following the first day of implementation of Requirement R3. After NERC reports on the data in a compliance filing, the Commission will consider what further action, if any, to take."	Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard	1/19/2017	Order 835	RM16-7	Para 23 and Para 46			

Table 3: Directives by Commission Order								
Directive Summary	**Document Name**	**Publication Date**	**Order No.**	**FERC ORDER / DOCKET**	**Paragraph Reference**	**Project Number**	**Project Name**	**Project Type**
S-ref 10955-P23: "We further direct NERC to study and submit a report to the Commission with findings regarding reliability risks associated with most severe single contingency exceedances that do not result in energy emergencies."	Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard	1/19/2017	Order 835	RM16-7	Para 23			
S-ref 10956- P68: "[W]e direct NERC to assign a "high" violation risk factor to Reliability Standard BAL-002-2, Requirements R1 and R2."	Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard	1/19/2017	Order 835	RM16-7	Para 68			

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Remedial Action Schemes Reliability Standard	)	Docket No. RM16-20-000

COMMENTS OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC") hereby provides comments on the Notice of Proposed Rulemaking ("NOPR") issued by the Federal Energy Regulatory Commission ("FERC" or the "Commission") on January 19, 2017 in the above-captioned docket proposing to approve NERC Reliability Standard PRC-012-2.[1] The purpose of proposed Reliability Standard PRC-012-2 is to ensure that Remedial Action Schemes ("RAS") do not introduce unintentional or unacceptable reliability risks to the Bulk Electric System ("BES"). Proposed Reliability Standard PRC-012-2 enhances reliability by requiring a centralized review process for each new or functionally modified RAS prior to implementation, obligating entities to complete periodic evaluations, tests, and operational analyses for all RAS, and requiring the entity with a wide-area view to establish a database with pertinent information about each RAS.

NERC supports the Commission's proposal to approve the proposed Reliability Standard and urges the Commission to approve the proposed Reliability Standard without directing modifications. The following comments address the Commission's request for comment on the "limited impact" RAS designation, as follows:

- Section 1 provides an overview of the "limited impact" RAS designation under PRC-012-1;

[1] *Remedial Action Schemes Reliability Standard*, Notice of Proposed Rulemaking, 158 FERC ¶ 61,042 (2017) ("NOPR").

- Section 2 confirms that proposed Reliability Standard PRC-012-2 does not modify or supersede any system performance obligations under Reliability Standard TPL-001-4;

- Section 3 confirms that Local Area Protection Schemes ("LAPS") in the Western Electricity Coordinating Council ("WECC") and Type III RAS in the Northeast Power Coordinating Council ("NPCC") must comply with proposed Reliability Standard TPL-001-4 before and after the effective date of proposed Reliability Standard PRC-012-2; and

- Section 4 provides that it is not necessary to include the term "limited impact" RAS in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary").

1. Limited Impact RAS Designations

As NERC explained in its petition in this proceeding, RAS vary widely in complexity and impact on the BES. Recognizing these distinctions, proposed Reliability Standard PRC-012-2 differentiates between those RAS that could significantly impact the reliable operation of the BES if the RAS misoperates or fails to operate from those that could not have a significant impact. For those RAS that present greater risk to BES reliability, PRC-012-2 requires an additional level of scrutiny in the design, implementation, and review of the RAS to help ensure a higher level of dependability (e.g., that a single component failure or malfunction would not result in significant adverse reliability impact). For those RAS with a more limited impact on BES reliability, the design, implementation, and review requirements are tailored to the lower risks they pose to BES reliability and provide a cost-effective approach to mitigating those risks without introducing unnecessary complexity in the RAS design.

Specifically, proposed Reliability Standard PRC-012-2 provides that the Reliability Coordinator may designate a RAS as a "limited impact" RAS if the RAS cannot, by inadvertent operation or failure to operate, cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations.[2]

[2] *Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standard PRC-012-2* at 22-27, Docket No. RM16-20-000 (Aug. 5, 2016) ("Petition").

Proposed Reliability Standard PRC-012-2 distinguishes "limited impact" RAS from all other RAS in two limited areas: (1) the substance of the Planning Coordinator's review of the RAS pursuant to Requirement R4; and (2) the periodicity of the RAS-entity's functional test of each RAS under Requirement R8.[3]

In evaluating a "limited impact" RAS every five years pursuant to Requirement R4, the Planning Coordinator must determine whether: (1) it continues to mitigate the System condition(s) or Contingency(ies) for which it was designed (Part 4.1.1); (2) it avoids adverse interactions with other RAS, and protection and control systems (Part 4.1.2); and (3) the inadvertent operation of the RAS or the failure of the RAS would not cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations (Part 4.1.3).[4]

In contrast, for non-limited impact RAS, given the greater risk they present to reliability, the Planning Coordinator must also determine whether:

- The possible inadvertent operation of the RAS, resulting from any single RAS component malfunction, satisfies all of the following: the BES shall remain stable; Cascading shall not occur; applicable Facility Ratings shall not be exceeded; BES voltages shall be within post-Contingency voltage limits and post-Contingency voltage deviation limits established by the Transmission Planner and the Planning Coordinator; and transient voltage responses shall be within acceptable limits established by the Transmission Planner and the Planning Coordinator (Part 4.1.4).

- A single component failure in the RAS, when the RAS is intended to operate, would prevent the BES from meeting the same performance requirements (defined in Reliability Standard TPL-001-4 or its successor) as those required for the events and conditions for which the RAS is designed (Part 4.1.5).

These tests help ensure that should a single component of the RAS malfunction or fail, the RAS would continue to meet its design objectives and not have any significant adverse effect on BES

[3] As discussed in the Petition at 4, the RAS-entity is the entity (Transmission Owner, Generation Owner, or Distribution Provider) that owns all or part of a RAS.

[4] Petition at 22.

performance. Requiring entities to perform the single component failure and single component malfunction tests for "limited impact" RAS, however, would add unnecessary complexity and costs to the RAS design and implementation with little benefit to reliability.

Additionally, pursuant to Requirement R8, a RAS-entity must perform a functional test of its "limited impact" RAS at least once every 12 calendar years. For all other RAS, the RAS-entity needs to perform the functional test at least once every six years. The timeframes in Requirement R8 are designed to balance the resources required to perform the testing and the potential reliability impacts to the BES created by undiscovered latent failures that could cause an incorrect operation of the RAS. Longer test intervals for "limited impact" RAS are acceptable because incorrect operations or failures to operate present a low reliability risk to the BES. It is important to note that the Protection Systems (with the exception of the "controller") that comprise the "limited impact" RAS are already covered under Reliability Standard PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance.

Other than the two instances discussed above, the "limited impact" RAS designation is not relevant to any other requirement in proposed Reliability Standard PRC-012-2 or any other Reliability Standard, including TPL-001-4, as the Commission proposes to clarify.

2. Proposed Reliability Standard PRC-012-2 Does Not Modify or Supersede Any System Performance Obligation Under Reliability Standard TPL-001-4

Consistent with NERC's Petition,[5] NERC supports the Commission's proposed clarification that proposed Reliability Standard PRC-012-2 does not modify or supersede any System performance obligations under Reliability Standard TPL-001-4. Proposed Reliability Standard PRC-012-2 presupposes that entities are complying with the performance requirements

[5] *Id*. at 28-29.

in TPL-001-4. Proposed PRC-012-2 simply adds design, implementation, and review requirements to help ensure that a RAS enhances reliability and does not introduce unintentional or unacceptable reliability risks.[6] Nothing in proposed Reliability Standard PRC-012-2 or the designation of a RAS as "limited impact" exempts an entity from meeting its performance requirements under TPL-001-4, including the requirement that Non-Consequential Load Loss may not exceed 75 MW for certain Category P1, P2, or P3 contingencies, as provided in Table 1 and footnote 12 of TPL-001-4.

In performing the assessments required pursuant to Reliability Standard TPL-001-4, an entity must consider all RAS, whether designated as "limited impact" or not. While Reliability Standard TPL-001-4, Requirement R2, Part 2.7.1 recognizes that entities may use a RAS as a method for meeting the performance obligations of Table 1, TPL-001-4 does not distinguish between different types of RAS. As such, entities must satisfy the performance requirements of TPL-001-4 considering the actions of "limited impact" RAS and non-limited impact RAS alike.

3. LAPS in WECC and Type III RAS in NPCC Must Be Compliant with Reliability Standard TPL-001-4 Before and After the Effective Date of Proposed Reliability Standard PRC-012-2

As discussed in the Petition, prior to development of proposed Reliability Standard PRC 012-2, two NERC Regional Entities, WECC and NPCC, used individual RAS classification regimes to identify RAS that would meet criteria similar to those for RAS described as "limited impact" in proposed Reliability Standard PRC-012-2. In the WECC region, such RAS are classified as LAPS and in the NPCC region they are classified as Type III RAS. For purposes of PRC-012-2, LAPS and Type III RAS are considered "limited impact" RAS, subject to future review and potential reclassification by the Planning Coordinator under Requirement R4.

[6] For purposes of the assessments performed under TPL-001-4, the entity is not required to take into account the potential failure or misoperation of the RAS (i.e., all RAS are assumed to operate correctly). Proposed Reliability Standard PRC-012-2 complements TPL-001-4 as is provides the mechanism to require entities to take steps to prevent the failure or misoperation of a RAS.

In the NOPR, the Commission requested "comment on the processes used to ensure the LAPS or Type III RAS will be compliant with Reliability Standard TPL-001-4 prior to the effective date of Reliability Standard PRC-012-2, including a description of considerations on whether the load disconnected by each RAS installation is consequential or non-consequential, and if Non-Consequential Load Loss is greater than 75 MW."[7] As discussed above with respect to "limited impact" RAS under proposed PRC-012-2, the designation of a RAS as a LAPS in WECC or Type III in NPCC does not modify or supersede an entity's responsibility under Reliability Standard TPL-001-4 to satisfy the performance requirements therein. In performing the assessments required pursuant to Reliability Standard TPL-001-4, an entity must consider all RAS, including LAPS or Type III RAS. TPL-001-4 does not distinguish between different types of RAS or exempt LAPS or Type III RAS from any of the performance requirements. The applicable entities must satisfy the performance requirements of TPL-001-4 considering the actions of all RAS, both before and after the effective date of PRC-012-2.

Nevertheless, NERC understands that both NPCC and WECC have processes that help ensure that RAS are compliant with the performance requirements of TPL-001-4. NPCC's process for RAS (referred to as a Special Protection System ("SPS") in NPCC) design and approval is found in NPCC's Regional Reliability Reference Directory #7 ("NPCC Directory #7").[8] The initial activity for reviewing new or modified RAS in NPCC is for the NPCC Task Force on System Studies to verify the "Type" of RAS by determining its impact on the BES. For Type III RAS, NPCC Directory #7 provides, in part, that the relevant NPCC task force must confirm that the RAS conforms to the criteria in NPCC Regional Reliability Reference Directory #1 ("NPCC Directory

[7] NOPR at 75.

[8] NPCC Directory #7 is available at: https://www.npcc.org/Standards/Directories/Directory%207_SPS_%20clean_20150331_GJD.pdf.

#1").[9] NPCC Directory #1 contains the planning criteria for the NPCC region as well as design and operations requirements. Table 1 of NPCC Directory #1, which provides planning design criteria, contingency events, fault type and performance requirements, is consistent with, yet more stringent than, the performance requirements appearing in Table 1 of TPL-001-4. NERC understands that use of this process helps ensure that RAS used in the NPCC region comply with the performance requirements in TPL-001-4, including consideration of load disconnected by each RAS installation.

For reference, NPCC has only one Type III RAS in the United States that is a load rejection type (i.e. that drops load for a specific system condition). NERC understands that this Type III RAS, which was installed in 2006, prior to the effective date of TPL-001-4, is infrequently "armed" (less than 1% of the time) and only when specific lines or equipment are not in service, such as during maintenance activities. The RAS was initially proposed, designed, and implemented for very specific operating conditions and not as a result of meeting performance requirements in Reliability Standard TPL-001-4. Further, NERC understands that the owner of this RAS is currently developing new transmission projects that will result in the retirement of the RAS within six years.

As in NPCC, WECC's review of RAS includes consideration of compliance with Reliability Standard TPL-001-4. WECC's Remedial Action Scheme Reliability Subcommittee ("RASRS") reviews all RAS modifications, new RAS, and retiring RAS. The RASRS review process, as outlined in the WECC Guideline *Procedure and Information Required for RAS*

[9] NPCC Directory #1 is available at: https://www.npcc.org/Standards/Directories/Directory_1_TFCP_rev_20151001_GJD.pdf.

Assessment, verifies affected loads, generation, and protection systems.[10] The RASRS review process is specifically oriented to review RAS that are designed to result in System performance meeting the TPL Reliability Standards. The RASRS performs a more detailed review for those RAS that may have a significant System performance impact. Given the lower risk associated with a RAS classified as a LAPS, NERC understands that the RASRS review primarily focuses on the reliability impacts of the LAPS and confirmation that the classification is appropriate, although a more detailed review of the LAPS may be performed. NERC understands that there are only 16 LAPS in the United States designed to shed load.[11] Seven of those LAPS are designed to shed load to mitigate Category P1, P2, or P3 events, none of which shed more than 75 MW. The other nine LAPS in the United States designed to shed load are used to mitigate Category P4-P7 events.

4. The Term "Limited Impact RAS" Should Not Be Defined in the NERC Glossary

In the NOPR, the Commission requested "comment on whether the term 'limited impact RAS' should be defined in the [NERC Glossary]."[12] NERC Glossary terms are typically developed for two purposes: (1) to establish a single meaning for a term or concept used across several different Reliability Standards or multiple times within a single Reliability Standard, or (2) to provide for a more readable standard by creating a shorthand reference to avoid unnecessary repetition. Neither of these reasons necessitate creating a definition for the term "limited impact" RAS.

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[10] The WECC Guideline *Procedure and Information Required for RAS Assessment* is available at https://www.wecc.biz/_layouts/15/WopiFrame.aspx?sourcedoc=/Administrative/10a%20Procedure%20and%20Information%20Required%20for%20RAS%20Assessment.pdf&action=default&DefaultItemOpen=1.

[11] There are over 180 LAPS in the WECC region but only 23 of those LAPS are designed to shed load, 16 of which are located in the United States.

[12] NOPR at P 17.

During development of proposed Reliability Standard PRC-012-2, the standard drafting team considered this issue, ultimately concluding that a universally applicable definition was not necessary or preferable. Diversity among the different types, functions, and placements of RAS make it difficult to establish a definition of "limited impact" RAS applicable across North America.[13] As such, instead of developing a one-size-fits-all definition, the standard drafting team determined it was preferable to: (1) include in the proposed standard a high level statement outlining the type of impact a "limited impact" RAS could not cause or contribute to as a result of inadvertent operation or a failure to operate; (2) provide Reliability Coordinators the authority to designate a RAS as "limited impact" on a case-by-case basis as appropriate for its area; and (3) require Planning Coordinators to verify on a periodic basis whether the RAS continues to be "limited impact."[14] The approach in proposed Reliability Standard PRC-012-2 provides the necessary flexibility without sacrificing readability. As with all of its standards, NERC will assess whether there are ways to improve the proposed Reliability Standard following its implementation, including whether a NERC Glossary definition for "limited impact" RAS is necessary to promote clarity.

[13] *See* Petition at 25.

[14] As discussed in the Petition, the Reliability Coordinator is the appropriate entity to initially designate a RAS as "limited impact" as it has the wide-area view and understanding of the BES to determine whether a RAS could cause or contribute to BES Cascading, uncontrolled separation, angular instability, voltage instability, voltage collapse, or unacceptably damped oscillations. Additionally, the Planning Coordinator is the appropriate entity to verify that a RAS continues to be "limited impact" because the Planning Coordinator maintains a wide-area planning perspective to determine whether the designation still applies.

5. Conclusion

NERC respectfully requests that the Commission consider these comments and approve proposed Reliability Standard PRC-012-2 without modification.

Respectfully submitted,

/s/ Shamai Elstein
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Counsel for the North American Electric Reliability Corporation

Date: April 10, 2017

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 first quarter of 2017, in accordance with the January 16 Order. This variance information was

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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.*

posted on NERC's website and reviewed at the May 10, 2017 open meeting of the NERC Finance and Audit Committee ("FAC"). The unaudited report was accepted by the NERC Board of Trustees at its meeting on May 11, 2017.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[4]

Michael Walker*
Senior Vice President and Chief Financial and
Strategic Development Officer
Meredith M. Jolivert*
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III. DISCUSSION OF SIGNIFICANT VARIANCES BETWEEN 2017 BUDGET AND UNAUDITED ACTUAL 2017 RESULTS

The attached first quarter 2017 variance report compares actual (unaudited) financial results to NERC's budgeted expenditures as of March 31, 2017, and projected year-end 2017 financial results to NERC's total 2017 budgeted expenditures.

A. 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 $538K more than budgeted, primarily due to the allocation of additional staff resources to support program activities, and costs related to design of a new entity registration database. Costs associated with

[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 (2016), to allow the inclusion of more than two persons on the service list in this proceeding.

the entity registration database were budgeted in Information Technology 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.

B. Information Technology

Actual 2017 direct expenses plus net fixed asset expenditures for the Information Technology department are projected to be $575k under budget. ERO application development costs budgeted in IT will be charged to the relevant operating programs utilizing the application. Refer to the table on page 5 of the Attachment.

IV. 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: May 15, 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 15th day of May, 2017.

/s/ Meredith M. Jolivert

Meredith M. Jolivert
Counsel for North American Electric Reliability Corporation

ATTACHMENT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

North American Electric Reliability Corporation
Summary of Unaudited Results
March 31, 2017

Through March 31, 2017, NERC was $1.9M (10.4%) under its expense and fixed asset budget, including costs related to the Cyber Risk Information Sharing Program (CRISP). NERC is projecting to be approximately $503k (0.7%) over budget at year-end primarily due to higher than budget personnel, conference calls, consultants and contracts, and office expenses. The increase in consultant and contract expenses is offset by spending reductions in fixed assets.

Excluding the approved use of reserves, NERC was $2.0M (10.9%) under its expense and fixed asset budget through March and is projecting to be over budget $417k (0.6%) at year-end.

The over budget variance (including reserve usage) of $502k projected for 2017 is offset by an over budget variance in funding of $144k. Therefore, the net impact to NERC's operations and operating contingency reserves for these 2017 projections is $358k, or approximately 0.5% of total budgeted expenditures.

Actual vs Budget (YTD) and Projection vs Total Budget (including CRISP)

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 20,351,538**	**$ 20,110,527**	**$ 241,012**	**1.2%**	**$ 70,296,074**	**$ 70,151,660**	**$ 144,413**	**0.2%**
EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	$ 10,062,307	$ 10,225,862	$ (163,555)	-1.6%	$ 38,701,038	$ 38,641,331	$ 59,707	0.2%
MEETINGS, TRAVEL and CONFERENCE CALLS	1,010,982	843,222	167,761	19.9%	3,753,651	3,372,886	380,764	11.3%
CONSULTANTS and CONTRACTS	2,145,844	3,507,575	(1,361,731)	-38.8%	13,751,417	13,127,749	623,668	4.8%
RENT	807,814	779,252	28,562	3.7%	3,117,009	3,117,009	-	0.0%
OFFICE COSTS, PROFESSIONAL SERVICES and MISC.	1,773,318	1,714,844	58,474	3.4%	7,142,825	6,864,475	278,350	4.1%
OTHER NON-OPERATING EXPENSES	11,739	26,681	(14,943)	-56.0%	106,725	106,725	-	0.0%
FIXED ASSET PURCHASES (excluding depreciation)	489,599	1,093,000	(603,401)	-55.2%	3,532,145	4,372,000	(839,855)	-19.2%
TOTAL EXPENSES and FIXED ASSETS	**$ 16,301,603**	**$ 18,190,436**	**$ (1,888,832)**	**-10.4%**	**$ 70,104,810**	**$ 69,602,175**	**$ 502,635**	**0.7%**
APPROVED USE of RESERVES	85,986	-	85,986		85,986	-	85,986	
TOTAL EXPENSES and FIXED ASSETS (excluding reserves)	**$ 16,215,617**	**$ 18,190,436**	**$ (1,974,818)**	**-10.9%**	**$ 70,018,824**	**$ 69,602,175**	**$ 416,649**	**0.6%**
FTEs	**188.2**	**189.9**	**(1.7)**	**-0.9%**	**189.9**	**189.9**	**-**	**0.0%**

NERC VARIANCES - excluding CRISP

NERC was $1.0M (6.2%) under budget and is currently projecting to be very close to budget at year-end ($565k or 0.9% over). The projected over budget variance is primarily due to higher anticipated costs in consultants and contracts expenses, conference calls expense, and office costs. These higher costs were substantially offset by lower expenses in fixed assets.

The following table and summary of variances by category reflect 2017 year-to-date (YTD) actual and projected results without CRISP. A summary of results for CRISP is provided on page 6.

Actual vs Budget (YTD) and Projection vs Total Budget
(Excluding CRISP)

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 16,267,995**	**$ 16,270,123**	**$ (2,129)**	**0.0%**	**$ 61,997,027**	**$ 61,859,220**	**$ 137,807**	**0.2%**
EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	$ 9,882,389	$ 10,023,173	$ (140,784)	-1.4%	$ 37,974,921	$ 37,872,960	$ 101,961	0.3%
MEETINGS, TRAVEL and CONFERENCE CALLS	1,004,996	825,798	179,198	21.7%	3,686,195	3,303,194	383,001	11.6%
CONSULTANTS and CONTRACTS	1,337,792	2,035,426	(697,634)	-34.3%	7,783,073	7,239,155	543,918	7.5%
RENT	807,814	779,252	28,562	3.7%	3,117,009	3,117,009	-	0.0%
OFFICE COSTS, PROFESSIONAL SERVICES and MISC.	1,738,143	1,594,611	143,532	9.0%	6,661,892	6,383,542	278,350	4.4%
OTHER NON-OPERATING EXPENSES	11,739	26,681	(14,943)	-56.0%	106,725	106,725	-	0.0%
FIXED ASSET PURCHASES (excluding depreciation)	468,123	1,005,500	(537,377)	-53.4%	3,261,895	4,022,000	(760,105)	-18.9%
INDIRECT EXPENSES and ALLOCATION OF FIXED ASSETS	(153,430)	(190,053)	36,623	-19.3%	(716,823)	(734,850)	18,027	-2.5%
TOTAL	**$ 15,097,565**	**$ 16,100,389**	**$ (1,002,824)**	**-6.2%**	**$ 61,874,887**	**$ 61,309,735**	**$ 565,152**	**0.9%**
FTEs	**185.6**	**187.1**	**(1.5)**	**-0.8%**	**187.1**	**187.1**	**-**	**0.0%**

Following is a brief summary of variances by major categories (excluding CRISP):

- Personnel expenses were under budget $141k (1.4%) and are projected to be slightly over budget ($102k or 0.3%) at year-end based on current staffing assumptions. The 2017 personnel budget was based on 202 positions, reduced by a vacancy rate of 6.0% (accounting for attrition and timing of new hires). Actual attrition through March 31st was 1.6%.

- Meeting, travel and conferencing expenses were collectively over budget $179k (21.7%), and are projected to be $383k (11.6%) over budget at year-end. The actual and projected over budget meeting expenses related in part to the approved use of reserves for an ERO leadership conference. Additionally, NERC incurred higher than budgeted costs associated with the Human Performance Workshop, but those costs were substantially offset by higher than budgeted workshop fees. The projected over budget variance in

conferencing expenses is due to a delay in canceling services from the previous provider and transitional support for the new audio/video system, although IT intends for these costs to be offset by other savings.

- Consultant and Contract expenses were under budget $698k (34.3%), and are projected to be $544k (7.5%) over budget at year-end. In addition to smaller variances in other departments, the projected over budget variance is primarily due to the portal improvement project in E-ISAC and additional outside support needed for IT. In both cases, the additional consultant and contract costs were offset by reductions in fixed assets. The E-ISAC portal project was originally anticipated to be a software development project and budgeted in fixed assets. However, the project will likely be using an existing software platform and NERC will be recognizing ongoing license and maintenance expenses instead of fixed asset developmental costs.

SUMMARY OF CONSULTANT AND CONTRACT EXPENSES BY DEPARTMENT

CONSULTANTS and CONTRACTS	Actual	Budget	Variance Over (Under)	Annual Projection	Annual Budget	Variance Over (Under)
COMPLIANCE ASSURANCE	$ -	$ 12,500	$ (12,500)	$ 35,800	$ 50,000	$ (14,200)
RELIABILITY ASSESSMENTS and SYSTEM ANALYSIS	35,093	131,250	(96,157)	503,020	525,000	(21,980)
RELIABILITY RISK MANAGEMENT	748,624	681,621	67,003	1,823,932	1,823,932	(0)
E-ISAC	79,473	224,959	(145,486)	1,204,085	899,835	304,250
TRAINING, EDUCATION & OPERATOR CERTIFICATION	157,932	145,150	12,782	718,614	580,600	138,014
POLICY and EXTERNAL AFFAIRS	1,276	3,750	(2,474)	15,000	15,000	-
INFORMATION TECHNOLOGY	299,245	578,197	(278,952)	2,510,622	2,312,787	197,835
HUMAN RESOURCES	9,500	143,750	(134,250)	575,000	575,000	-
FINANCE and ACCOUNTING	6,649	114,250	(107,601)	397,000	457,000	(60,000)
TOTAL (excluding CRISP)	**$ 1,337,792**	**$ 2,035,426**	**$ (697,634)**	**$ 7,783,073**	**$ 7,239,155**	**$ 543,918**
CRISP	808,052	1,472,149	(664,096)	5,968,344	5,888,594	79,750
TOTAL CONTRACTS and CONSULTANTS	**$ 2,145,844**	**$ 3,507,575**	**$ (1,361,731)**	**$ 13,751,417**	**$ 13,127,749**	**$ 623,668**

- Office costs, professional services and miscellaneous expenses were collectively over budget $144k (9.0%), and are projected to be $278k (4.4%) over budget at year-end. The projected over budget office costs are primarily related to the expense treatment of the new audio/video lease agreement. NERC has historically budgeted purchases for A/V equipment in fixed assets, but due to the timing of the final lease transaction and leasing of this equipment, the fixed asset expenditures will be under budget and offset by higher than budgeted operating expenses due to the decision to lease these assets in lieu of purchasing. Going forward after 2017, the lease will be budgeted and expensed in the same account.

- Fixed Asset Purchases (excluding depreciation) were $537k (53.4%) under budget and projected to be $760k (18.9%) under budget at year-end. The under budget variance is primarily related to the costs associated with both the audio/video lease assets and E-ISAC portal work. As previously mentioned, both were originally budgeted in fixed assets, but were recognized as expenses in other areas due to the nature of the transactions.

SUMMARY OF VARIANCES BY PROGRAM

The following table reflects variances by department as of March 31, 2017.

DIRECT EXPENSES and NET FIXED ASSETS	2017 Actual	2017 Budget	Variance Over/(Under)	2017 Projection	2017 Budget	Variance Over/(Under)
RELIABILITY STANDARDS	$ 879,883	$ 945,599	$ (65,715)	$ 3,533,195	$ 3,629,945	$ (96,750)
COMPLIANCE ANALYSIS, CERTICATION and REGISTRATION	558,343	443,306	115,037	2,224,479	1,686,689	537,789
COMPLIANCE ASSURANCE	1,023,473	994,531	28,941	4,176,007	3,816,924	359,083
ENFORCEMENT	649,579	625,456	24,123	2,343,364	2,371,347	(27,984)
RELIABILITY ASSESSMENTS and SYSTEM ANALYSIS	867,613	1,001,197	(133,585)	3,739,404	3,861,344	(121,941)
RELIABILITY RISK MANAGEMENT	2,555,627	2,165,553	390,074	7,981,327	7,529,324	452,003
E-ISAC	1,123,336	1,495,475	(372,139)	6,092,187	5,813,801	278,387
TRAINIING, EDUCATION and OPERATOR CERTIFICATION	478,724	494,574	(15,850)	1,858,552	1,920,376	(61,823)
GENERAL and ADMINISTRATIVE and EXECUTIVE	2,140,485	2,086,756	53,728	7,987,718	8,171,444	(183,725)
POLICY and EXTERNAL AFFAIRS	595,542	541,837	53,705	2,075,071	2,034,533	40,538
LEGAL and REGULATORY	623,975	869,203	(245,228)	3,030,976	3,292,379	(261,403)
INFORMATION TECHNOLOGY	2,513,252	3,184,284	(671,032)	11,905,763	12,480,846	(575,083)
HUMAN RESOURCES	250,123	410,922	(160,799)	1,587,857	1,608,583	(20,726)
FINANCE and ACCOUNTING	991,040	1,031,748	(40,708)	4,056,956	3,827,050	229,907
TOTAL (excluding CRISP)	**$ 15,250,995**	**$ 16,290,442**	**$ (1,039,447)**	**$ 62,592,856**	**$ 62,044,585**	**$ 548,271**

Following is a brief summary of significant variances:

- Compliance Analysis, Certification and Registration; Compliance Assurance; E-ISAC; Finance and Accounting – Over budget YTD and projected to be over budget at year-end primarily due to additional resources added to support ongoing program activities within these program areas. The additional resources in Finance and Accounting are to support the Internal Audit and Risk Management department.
- Standards; Reliability Assessments and System Analysis; Legal and Regulatory – Under budget year-to-date and projected to be under budget at year-end due to lower than budgeted personnel expenses.
- Reliability Risk Management (includes Event Analysis, Performance Analysis, and Situation Awareness departments) – Over budget YTD and expected to be over budget at year-end primarily related to ERO Application development costs that are budgeted in IT but recorded in the programs utilizing the applications.

- Information Technology – Under budget year-to-date and projected to be under budget at year-end. ERO application development costs budgeted in IT will be charged to the relevant operating programs utilizing the application. The following table shows the detail of project costs allocated to other departments.

Information Technology		2017 YTD		2017 Projection
Actual	$	2,513,252	$	11,905,968
Budget		3,184,284		12,480,846
Variance Over (Under)	$	(671,032)	$	(574,878)
Transferred Projects				
Entity Registration (Registration)	$	-	$	125,000
MIDAS (RRM)		139,475		362,600
FERC 854 (RRM)		58,050		86,400
Total Transferrred	$	197,525	$	574,000
Adjusted Variance Over (Under)	**$**	**(473,507)**	**$**	**(878)**

BOARD OF TRUSTEES EXPENSES

Board of Trustees expenses were under budget YTD by $45k (10.2%) and are expected to be approximately on budget at year-end.

Board of Trustee Expenses	Actual	Budget	Variance Over (Under)	%
Meetings and Travel Expenses				
Quarterly Board Meetings and Conference Calls	$ 51,256	$ 69,750	$ (18,494)	-26.5%
Trustee Travel	44,698	39,332	5,366	13.6%
Total Board of Trustees Meetings and Travel Expenses	**$ 95,954**	**$ 109,082**	**$ (13,128)**	**-12.0%**
Professional Services				
Independent Trustee Fees	299,585	306,500	(6,915)	-2.3%
Trustee Search Fees		25,000	(25,000)	-100.0%
Total Board of Trustee Professional Services Expenses	**$ 299,585**	**$ 331,500**	**$ (31,915)**	**-9.6%**
Total Board of Trustee Expenses	**$ 395,539**	**$ 440,582**	**$ (45,043)**	**-10.2%**

CRISP VARIANCES

CRISP was $886k (42.4%) under budget YTD and is projected to be $63k (0.8%) under budget at year-end.

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
TOTAL FUNDING	**$ 4,083,544**	**$ 3,840,404**	**$ 243,140**	**6.3%**	**$ 8,299,047**	**$ 8,292,441**	**$ 6,606**	**0.1%**
EXPENSES and FIXED ASSETS								
PERSONNEL EXPENSES	$ 179,918	$ 202,689	$ (22,771)		$ 726,117	$ 768,371	$ (42,254)	
MEETINGS, TRAVEL and CONFERENCE CALLS	5,986	17,423	(11,437)		67,455	69,692	(2,237)	
CONSULTANTS and CONTRACTS	808,052	1,472,149	(664,096)		5,968,344	5,888,594	79,750	
RENT	-	-	-		-	-	-	
OFFICE COSTS, PROFESSIONAL SERVICES and MISC.	35,175	120,233	(85,058)		480,933	480,933	-	
OTHER NON-OPERATING EXPENSES	-	-	-		-	-	-	
FIXED ASSET PURCHASES (excluding depreciation)	21,477	87,500	(66,024)		270,250	350,000	(79,750)	
INDIRECT EXPENSES and ALLOCATION OF FIXED ASSETS	153,430	190,053	(36,623)		716,823	734,850	(18,028)	
TOTAL EXPENSES and FIXED ASSETS	**$ 1,204,038**	**$ 2,090,046**	**$ (886,007)**	**-42.4%**	**$ 8,229,923**	**$ 8,292,441**	**$ (62,519)**	**-0.8%**

OPERATING RESERVES – Current Balances

The balance in working capital and operating reserves was $11.7M, which was $2.8M higher than budget. The increase was primarily due to higher CRISP reserves, which increased $2.9M due to timing differences between receipt of third-party funding for CRISP, which occurs at the beginning of the year, and expenses incurred throughout the year.

				March 31, 2017 Reserve Balances				
	Actual	Budget	Variance Over (Under)	Future Obligations Reserve	Operating Contingency Reserve	System Operator Reserves	***CRISP Reserves	Assessment Stabilization Reserve
2017 Beginning Reserve Balances	8,782,011	7,828,700	953,311	2,875,467	2,307,531	828,013	500,000	2,271,000
Change in Reserves from Current Year Operations								
Change in Reserves from budgeted operations	4,197,768	1,920,091	2,277,677	-	1,386,752	(68,490)	2,879,506	-
Approved use of reserves	(147,833)	-	(147,833)	(53,308)	(85,986)	(8,539)	-	-
	-	-	-	-	-	-	-	-
Capital Financing	-	-	-	-	-	-	-	-
Proceeds from Financing Activities (non-current only)	-	-	-	-	-	-	-	-
Debt Service	(181,567)	(246,425)	64,858	-	(181,567)	-	-	-
Other adjustments to reserves**	(933,529)	(600,000)	(333,529)	(333,529)	-	-	-	(600,000)
Reserve Balance	11,716,850	8,902,366	2,814,484	2,488,630	3,426,731	750,984	3,379,506	1,671,000

** Represents transactions recorded only on the Statement of Financial Position (balance sheet) and do not impact the Statement of Activities (income statement), including recording of capitalized leases, amortization of future obligations and funding the 457f plan.
*** Represents $500k of insurance reserves, plus 2017 CRISP funding billed, net of 2017 actual YTD expenses.

OPERATING RESERVES – Year-End Projection

The current year-end projection in total operating reserves is $8.1M, 0.5% ($333k) more than budgeted, including $2.6M in the Operating Contingency Reserve (OCR) and $1.7M in the Assessment Stabilization Reserve (ASR).

				2017 Projected Year End Reserve Balances				
	2017 Projection	2017 Budget	Variance Over (Under)	Future Obligations Reserve	Operating Contingency Reserve	System Operator Reserves	***CRISP Reserves	Assessment Stabilization Reserve
2017 Beginning Reserve Balances	8,782,011	7,828,700	953,311	2,875,467	2,307,531	828,013	500,000	2,271,000
Change in Reserves from Current Year Operations								
Change in Reserves from budgeted operations	281,358	549,485	(268,127)	-	104,551	107,683	69,124	-
Approved use of reserves	(90,095)	-	(90,095)	84,623	(85,986)	(88,732)	-	-
	-	-	-	-	-	-	-	-
Capital Financing	-	-	-	-	-	-	-	-
Proceeds from Financing Activities (non-current only)	966,667	966,667	-	-	966,667	-	-	-
Debt Service	(719,522)	(985,750)	266,228	-	(719,522)	-	-	-
Other adjustments to reserves**	(1,128,397)	(600,000)	(528,397)	(528,397)	-	-	-	(600,000)
Reserve Balance	**8,092,022**	**7,759,102**	**332,921**	**2,431,694**	**2,573,241**	**846,964**	**569,124**	**1,671,000**

** Represents transactions recorded only on the Statement of Financial Position (balance sheet) and do not impact the Statement of Activities (income statement), including recording of capitalized leases, amortization of future obligations and funding the 457f plan.
*** Represents $500k of insurance reserves, plus 2017 CRISP funding billed, net of 2017 actual YTD expenses.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
Statement of Activities and Fixed Assets Budget
(Unaudited)
For the period ended 03/31/2017

	Actual	Budget	Variance Over (Under)	%	Annual Projection	Annual Budget	Variance Over (Under)	%
Funding								
Assessments	$ 14,964,078	$ 14,964,078	0		$ 59,856,314	$ 59,856,314	$ -	
Assessment Stabilization Reserves - Penalties	1,100,000	1,100,000	0		1,100,000	1,100,000	-	
Assessment Stabilization Reserves - Non-Penalties	-	-	-		-	-	-	
Third-Party Funding (CRISP)	3,736,712	3,495,223	241,489		6,990,447	6,990,447	-	
Testing	414,420	480,475	(66,056)		1,921,900	1,921,900	-	
Services & Software	3,000	12,500	(9,500)		50,000	50,000	-	
Workshop Fees	115,300	57,500	57,800		305,300	230,000	75,300	
Interest	18,028	750	17,278		72,113	3,000	69,113	
Miscellaneous	-	-	-		-	-	-	
Total Funding	$ 20,351,538	$ 20,110,527	$ 241,012	1.2%	$ 70,296,074	$ 70,151,660	$ 144,413	0.2%
Expenses								
Personnel Expenses								
Salaries	$ 7,515,488	$ 7,545,194	$ (29,706)		$ 30,202,897	$ 30,073,438	$ 129,459	
Payroll Taxes	836,399	849,836	(13,436)		1,843,079	1,847,130	(4,052)	
Employee Benefits	867,124	917,102	(49,977)		3,635,671	3,643,806	(8,135)	
Savings & Retirement	843,295	913,731	(70,436)		3,019,391	3,076,956	(57,565)	
Total Personnel Expenses	$ 10,062,307	$ 10,225,862	$ (163,555)	-1.6%	$ 38,701,038	$ 38,641,331	$ 59,707	0.2%
Meeting Expenses								
Meetings	$ 368,527	$ 267,875	$ 100,652		$ 1,174,000	$ 1,071,500	$ 102,500	
Travel	568,808	550,947	17,861		2,261,286	2,203,786	57,499	
Conference Calls	73,648	24,400	49,248		318,365	97,600	220,765	
Total Meeting Expenses	$ 1,010,982	$ 843,222	$ 167,761	19.9%	$ 3,753,651	$ 3,372,886	$ 380,764	11.3%
Operating Expenses								
Consultants and Contracts	$ 2,145,844	$ 3,507,575	$ (1,361,731)		$ 13,751,417	$ 13,127,749	$ 623,668	
Rent & Improvements	807,814	779,252	28,562		3,117,009	3,117,009	-	
Office Costs	1,270,908	1,088,560	182,348		4,631,940	4,359,340	272,600	
Professional Services	497,663	617,034	(119,371)		2,468,135	2,468,135	-	
Miscellaneous	4,748	9,250	(4,502)		42,750	37,000	5,750	
Depreciation	665,856	422,864	242,992		1,691,457	1,691,457	-	
Total Operating Expenses	$ 5,392,832	$ 6,424,535	$ (1,031,703)	-16.1%	$ 25,702,708	$ 24,800,690	$ 902,018	3.6%
Other Non-Operating Expenses	$ 11,739	$ 26,681	$ (14,943)	-56.0%	$ 106,725	$ 106,725	$ -	0.0%
Indirect Expenses	$ -	$ -	$ -		$ -	$ -	$ -	
Total Expenses	$ 16,477,860	$ 17,520,300	$ (1,042,440)	-5.9%	$ 68,264,122	$ 66,921,632	$ 1,342,490	2.0%
Net Change in Assets	**$ 3,873,678**	**$ 2,590,227**	**$ 1,283,451**	**49.5%**	**$ 2,031,952**	**$ 3,230,028**	**$ (1,198,077)**	**-37.1%**
Fixed Assets								
Depreciation	$ (665,856)	$ (422,864)	$ (242,992)		$ (1,691,457)	$ (1,691,457)	$ -	
Computer & Software	468,123	643,000	(174,877)		2,446,669	2,572,000	(125,332)	
Furniture & Fixtures	-	-	-		-	-	-	
Equipment	21,477	450,000	(428,524)		1,085,477	1,800,000	(714,524)	
Leasehold Improvements	-	-	-		-	-	-	
					-	-	-	
Allocation of Fixed Assets	-	-	-		-	-	-	
Incr(Dec) in Fixed Assets	**$ (176,257)**	**$ 670,136**	**$ (846,393)**	**-126.3%**	**$ 1,840,688**	**$ 2,680,543**	**$ (839,855)**	**-31.3%**
Total Budget (Expenses plus Incr(Dec) in Fixed Assets)	**$ 16,301,603**	**$ 18,190,436**	**$ (1,888,832)**	**-10.4%**	**$ 70,104,810**	**$ 69,602,175**	**$ 502,635**	**0.7%**
Change in Reserves (Total Funding less Total Budget)	**4,049,935**	**1,920,091**	**2,129,844**	**110.9%**	**191,263**	**549,485**	**(358,222)**	
FTE's	**188.2**	**189.9**	**(1.7)**	**-0.9%**	**189.9**	**189.9**	**-**	**0.0%**

NORTH AMERICAN ELECTRIC RELIABILITY COPORATION
STATEMENT OF FINANCIAL POSITION
(Unaudited)
For the period ended 03/31/2017

	Unaudited 03/31/2017	Audited 12/31/2016	Working Capital and Operating Reserves 03/31/2017	Working Capital and Operating Reserves 12/31/2016
ASSETS				
Cash	$ 44,546,567	$ 54,523,917	$ 44,546,567	$ 54,523,917
Accounts receivable, net of allowance for uncollectible accounts of $0	19,622,518	3,784,074	19,622,518	3,784,074
Prepaid expenses and other current assets	2,269,363	2,046,006	2,269,363	2,046,006
Security deposit	125,585	125,585		
457(b) – Non-Qualified Deferred Compensation	1,109,883	1,109,883		
457(f) - Non-Qualified Deferred Compensation	720,449	473,741		
Property and equipment	10,614,957	10,791,214		
Total Assets	$ 79,009,322	$ 72,854,420		
LIABILITIES AND NET ASSETS				
Liabilities				
Current Portion				
Accounts payable and accrued expenses (includes vacation accrual)	$ 6,725,715	$ 4,288,119	$ (6,725,715)	$ (4,288,119)
Accrued incentive compensation	1,299,670	4,979,436	(1,299,670)	(4,979,436)
Deferred rent-current	416,947	396,121	(416,947)	(396,121)
Deferred compensation - current	-	-	-	-
Capital lease obligations - current	74,212	74,212	(74,212)	(74,212)
Accrued retirement liabilities	494,642	1,903,342	(494,642)	(1,903,342)
Debt service - current portion	1,238,940	1,238,940	(1,238,940)	(1,238,940)
Deferred income	20,840,612	12,301,737	(20,840,612)	(12,301,737)
Deferred revenue - CRISP	2,418,927	2,418,927	(2,418,927)	(2,418,927)
Regional assessments	21,211,931	23,471,153	(21,211,931)	(23,471,153)
Total Current Portion	$ 54,721,598	$ 51,071,987		
Long-Term Portion				
Deferred compensation[1]	1,552,582	1,527,437		
Long-Term Debt	443,867	625,433		
Penalties-Assessments stabilization	-	-		
Deferred Rent-non-current	2,903,818	3,015,784		
CRISP Insurance Reserve	500,000	500,000		
Capital lease obligations - non-current	77,541	77,541		
Total Long-Term Portion	$ 5,477,808	$ 5,746,195		
Total Liabilities	$ 60,199,405	$ 56,818,182		
Net Assets - unrestricted	$ 17,138,917	$ 13,265,238		
Net Assets - restricted	1,671,000	2,771,000	(1,671,000)	(2,771,000)
Total Liabilities and Net Assets	$ 79,009,322	$ 72,854,420	$ 10,045,850	$ 6,511,010

[1]Includes 457b and 457f liabilities, life insurance for former executive, and retiree medical

Working Capital and Operating Reserves	**$ 11,716,850**	**$ 6,075,782**

Financial Covenants	
1 - WC & OR Balance to Debt Service Ratio > 1.2 to 1.0 (=Working Capital / Debt Service)	9.46
2 - Liquidity to Debt Service Ratio > 1.5 to 1.0* (= (Cash - Regional Assessments - Restricted Net Assets)/ Debt Service)	17.49

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM15-11-__**

GEOMAGNETIC DISTURBANCE RESEARCH WORK PLAN OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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May 30, 2017

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ATTACHMENT 1: Order No. 830 GMD Research Work Plan

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	**)** **)**	**Docket No. RM15-11-__**

GEOMAGNETIC DISTURBANCE RESEARCH WORK PLAN OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Pursuant to paragraph 77 of the Federal Energy Regulatory Commission's ("FERC" or "Commission") Order No. 830,[1] the North American Electric Reliability Corporation ("NERC")[2] hereby submits a preliminary work plan to conduct research on topics related to geomagnetic disturbances ("GMD") and their impacts on the reliability of the Bulk-Power System ("BPS"). In Order No. 830, the Commission approved Reliability Standard TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events and directed NERC to, among other things, submit a work plan within six months of the effective date of the Final Rule describing how NERC would conduct research on the GMD-related topics specified by the Commission and any additional topics selected in NERC's discretion. To address the Commission's directive, NERC submits a preliminary Order No. 830 GMD Research Work Plan ("GMD Research Work Plan"), attached hereto as **Attachment 1.**

NERC collaborated with the Electric Power Research Institute ("EPRI") and the industry experts on the NERC GMD Task Force in developing the preliminary GMD Research Work Plan. EPRI's experience and expertise in electric industry research and development projects

[1] Order No. 830, *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 156 FERC ¶ 61,215 (2016), *reh'g denied*, Order No. 830-A, 158 FERC ¶ 61,041 (2017) ("Order No. 830").

[2] 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).

proved invaluable in identifying appropriate GMD research activities that build upon existing work to address the key GMD-related research areas specified by the Commission in Order No. 830. The specific research activities identified in the plan fall within nine broad research categories, called "Tasks," and are 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 BPS. The preliminary GMD Research Work Plan also includes the estimated costs and timeframe for completing each of the Tasks.

NERC expects that executing a research plan of the type contemplated by Order No. 830 would require an extensive, multi-year effort requiring scientific and technical expertise from a variety of disciplines. NERC does not currently maintain the necessary scientific expertise in fields such as space weather and geology to complete these research tasks in-house. Early estimates suggest that outsourcing the research tasks identified in the preliminary GMD Research Work Plan to those with the necessary expertise would cost a minimum of $2.7 million. NERC expects that funding the costs of executing such a plan would have a substantial impact on NERC's budget and therefore its annual assessments, which ultimately flow back to the consumer. Further, managing a large scale research project such as this is not one of NERC's "core competencies". NERC recognizes that other organizations, like EPRI, already possess the type of specialized expertise and experience necessary to effectively manage complex, multidisciplinary research projects and would therefore be better structured for this sort of undertaking.

Therefore, NERC plans to continue work over the next several months to identify an appropriate project administration structure to drive completion of the activities identified in the preliminary GMD Research Work Plan in a cost-effective and efficient manner. NERC's plans

for future work, which are described more fully in Section IV Next Steps, include continued outreach with representatives from governmental agencies in the U.S., Europe, and Canada. NERC's plans also include continued outreach to academia, vendors, and industry. The purpose of this outreach is to identify opportunities to leverage existing GMD-related work and research synergies, develop an appropriate research management structure, and identify alternative sources of funding. Further, NERC plans to conduct outreach to stakeholders regarding optimal approaches to structure the funding requirements, to include identifying opportunities for sharing costs, research management alternatives, and leveraging research responsibilities. These efforts, along with any comments and Commission guidance received through this proceeding, would inform the scope and structure of NERC's final GMD Research Work Plan and would aid in the development of a timetable for submitting informational filings to the Commission reporting on the results of research.

NERC expects to develop additional project details within the next six months and commits to keep Commission staff informed of the status of these efforts. As NERC continues its work to develop the final plan and address the resource and logistical challenges that lie ahead, NERC would welcome the Commission's guidance on the prioritization of specific Tasks, as discussed in Section IV below.

I. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[3]

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II. BACKGROUND

A. Order No. 830 Approving Reliability Standard TPL-007-1

On September 22, 2016, the Commission issued Order No. 830 approving Reliability Standard TPL-007-1 - Transmission System Planned Performance for Geomagnetic Disturbance Events. This standard was the second of two GMD Reliability Standards developed in response to the Commission's Order No. 779[4] to address the risks posed by GMD events on the reliable operation of the BPS. Reliability Standard TPL-007-1 requires owners and operators of the BPS to conduct initial and ongoing assessments of the potential impact of a benchmark GMD event

[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 (2016), to allow the inclusion of more than two persons on the service list in this proceeding.

[4] Order No. 779, *Reliability Standards for Geomagnetic Disturbances*, 143 FERC ¶ 61,147 (2013). The first GMD standard, Reliability Standard EOP-010-1 – Geomagnetic Disturbance Operations, was approved by the Commission in Order No. 797 in 2014 and requires Reliability Coordinators and applicable Transmission Operators to implement plans, processes, and procedures to mitigate the effects of GMD events on reliable operations. Order No. 797, *Reliability Standard for Geomagnetic Disturbance Operations*, 147 FERC ¶ 61,209, *reh'g denied*, Order No. 797-A, 149 FERC ¶ 61,027 (2014).

on BPS equipment and the BPS as a whole, and to develop and implement plans to protect against adverse BPS impacts resulting from the benchmark GMD event.

In Order No. 830, the Commission found that Reliability Standard TPL-007-1 addressed its directives for the second stage GMD Reliability Standard from Order No. 779 and stated that the standard "constitutes an important step in addressing the risks posed by GMD events to the Bulk Power System."[5] While approving the standard, the Commission directed NERC to develop certain modifications and undertake additional actions to further understanding of GMDs and their impacts on reliability, as summarized below.

B. The Commission Directs NERC to Modify TPL-007 and Conduct Further GMD Research

In Order No. 830, the Commission directed NERC to:

- develop certain modifications to TPL-007-1;[6] specifically:
  - develop revisions to the benchmark GMD event definition so that the reference peak geoelectric field amplitude is not based solely on spatially averaged data (P 44);
  - develop revisions to Requirement R6 to require registered entities to apply spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments (P 65);
  - develop revisions to the standard to require responsible entities to collect geomagnetically induced current ("GIC") monitoring and magnetometer data as necessary to enable model validation and situational awareness (P 88); and
  - develop revisions to the standard to include deadlines for the development and completion of any required Corrective Action Plans (PP 101-102);
- research specific GMD-related topics identified by the Commission and other topics in NERC's discretion, in accordance with a GMD research work plan filed with the Commission (the research should be informed by the ongoing GMD

[5] Order No. 830 at PP 1, 23.

[6] The Commission directed NERC to submit these modifications to the Commission within 18 months of the effective date of the Final Rule, or by May 2018. Order No. 830 at P 2. The standards modification directives are currently being considered by the Project 2013-03 Geomagnetic Disturbance Mitigation standard drafting team. This team expects to post the first draft of the revised TPL-007 standard in early summer 2017.

research efforts of government agencies, academic, and other publicly available contributors);[7] and

- collect GMD monitoring data pursuant to Section 1600 of the NERC Rules of Procedure and make that information available.[8]

This filing addresses the second of the Commission's directives to submit a work plan describing how NERC plans to conduct research on specific GMD-related topics. The Commission's directives and guidance for work plan topics, as well as how NERC plans to address those areas as part of its preliminary GMD Research Work Plan, are described in Section III below. NERC's preliminary GMD Research Work Plan also includes activities to facilitate the efficient and effective collection of GMD monitoring data in response to the Commission's third directive, as discussed below.

III. GMD RESEARCH WORK PLAN

In accordance with Order No. 830, NERC hereby submits a preliminary GMD Research Work Plan, attached hereto as **Attachment 1.** In this plan, NERC identifies specific research activities that are intended to derive insights into GMD-related impacts on reliability. NERC worked collaboratively with EPRI in developing this plan and received input on specific project activities from the GMD Task Force and NERC technical committees.

The research activities described in the preliminary GMD Research Work Plan are grouped into nine research Tasks. Each Task has an expected deliverable, such as a technical report or a publicly-available model or tool to aid in assessing GMD risk. As some tasks and activities are at the forefront of evolving science and engineering capabilities, the anticipated, expected, or desired deliverable may not be attained on a predicted timeline, or at all. In any event, these research activities should be pursued to the extent they reasonably can, taking into

[7] *See generally* Order No. 830 at P 77.

[8] *Id*. at PP 89, 93.

account expected costs, benefits, and available resources. This research would be helpful to advance understanding of GMD events and the potential impact on the reliable operation of the BPS. NERC contemplates that the final deliverable for each Task would be subject to technical and scientific review through the NERC GMD Task Force,[9] engaging outside researchers as necessary. In accordance with the Commission's directive, NERC would submit periodic informational filings to the Commission reporting on the results of its research.

In this section, NERC summarizes the nine research Tasks and how the activities under each Task are intended to address the Commission's research directives in Order No. 830 and promote increased understanding of and effective planning against GMD-related risks. NERC also provides an estimated timeframe for the completion of each Task based on estimates supplied by EPRI. **Attachment 1** includes a list of specific research activities for each Task, more detailed estimates of the time necessary to complete each of the activities falling under each Task, and a preliminary estimate of the costs to complete each Task.

A. Task 1: Further Analyze Spatial Averaging Used in the Benchmark GMD Event

Task 1 in NERC's preliminary GMD Research Work Plan is to perform further research and analysis on the use of spatial averaging in defining the GMD events that entities use when conducting the GMD Vulnerability Assessments required by the TPL-007 standard. Reliability Standard TPL-007-1 requires entities to conduct initial and ongoing assessments of the potential impact of a defined GMD event on BPS equipment and the BPS as a whole. This defined GMD event, referred to as the benchmark GMD event in TPL-007-1, and relies upon the use of an innovative spatial averaging technique to estimate the wide area impacts of a GMD event on the

[9] The NERC 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.

BPS. In Order No. 830, the Commission approved the benchmark GMD event but noted its concern that a spatially-averaged benchmark may not adequately account for localized peak geoelectric fields that could potentially affect reliable operations. Accordingly, the Commission directed NERC to revise the benchmark so that the definition does not rely upon spatially averaged data.[10] In addition, the Commission directed NERC, as part of the GMD research work plan, to "further 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)."[11]

Broadly speaking, the research falling under Task 1 would consist of two main components: (i) research to improve understanding of the characteristics and spatial scales of localized geoelectric field enhancements caused by severe GMD events; and (ii) research to determine the impacts of spatial averaging assumptions on BPS reliability. NERC estimates that this Task would require approximately 24-36 months to complete from start of work.

B. Task 2: Further Analyze Latitude Scaling

Task 2 in NERC's preliminary GMD Research Work Plan is to perform further analysis of the geomagnetic latitude scaling factors used in the TPL-007 standard. The benchmark GMD event defined in TPL-007-1 includes scaling factors to enable entities to tailor the geoelectric field to their specific location for conducting GMD Vulnerability Assessments. These factors are intended to account for differences in the intensity of a GMD event due to geographical considerations, such as geomagnetic latitude and local earth conductivity. Finding that there are "questions regarding the effects of GMDs at lower geomagnetic latitudes," the Commission

[10] Order No. 830 at PP 44, 47.

[11] *Id.* at P 26.

directed NERC to reexamine the geomagnetic latitude scaling factors provided in TPL-007-1.[12] Consistent with the Commission's directive, NERC would use existing models and develop new models to extrapolate from historical data the impacts of a large, 1-in-100 year GMD event on lower geomagnetic latitudes under this Task. NERC estimates that this Task would require approximately 24 months to complete from start of work.

C. Task 3: Improve Earth Conductivity Models for GIC Studies

Task 3 of NERC's preliminary GMD Research Work Plan is to perform further research to improve the accuracy and efficacy of the earth conductivity models used for GIC studies. In Order No. 830, the Commission expressed concerns regarding the ground conductivity models that form the basis for the earth conductivity scaling factors used in TPL-007-1 and directed NERC to study this issue as part of its GMD research work plan.[13] Accordingly, NERC's preliminary plan identifies research activities to address the Commission's specific concerns, including comparing the accuracy of GIC calculations derived from available 1D models with 3D models that have recently been developed for some areas of the U.S. and examining modeling to account for the so-called "coastal effects." NERC estimates that this Task would require approximately 24-36 months to complete from start of work.

D. Task 4: Study GIC Field Orientation for Transformer Thermal Impact Assessments

Task 4 of NERC's preliminary GMD Research Work Plan is focused on performing analysis to evaluate the ability of GIC flow calculated as specified in TPL-007 to represent worst-case transformer hot-spot heating conditions. Reliability Standard TPL-007-1 was designed to identify transformers that are potentially at risk from GIC flows experienced during a

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12 *Id.* at P 57.

13 *See id*. at PP 78-80.

severe GMD event. Requirement R6 of the standard requires owners of applicable transformers to perform transformer thermal impact assessments of transformers where the maximum effective GIC value for the benchmark GMD event, as provided in Requirement R5.1, is 75 A per phase or greater. The results of these assessments are then shared so they may be incorporated into the overall GMD Vulnerability Assessment and any necessary Corrective Action Plan. As described in NERC's Screening Criterion for Transformer Thermal Impact Assessment White Paper, this threshold was chosen because transformers with an effective GIC of less than 75 A per phase during the benchmark GMD event are unlikely to exceed known temperature limits established by technical organizations.[14]

In Order No. 830, the Commission directed NERC to perform additional research related to the transformer thermal impact assessments required by the TPL-007 standard. Specifically, the Commission directed NERC to study, as part of its GMD research work plan, how "the geoelectric field time series can be applied to a particular transformer so that the orientation of the time series, over time, will maximize GIC flow in the transformer . . . ."[15] Task 4 would therefore consist of work to determine how the benchmark geoelectric field wave shape can be applied to a particular transformer to determine worst-case hotspot heating. NERC estimates that this Task would require approximately 10-12 months to complete from start of work.

E. Task 5: Further Analyze the 75 A per Phase Criterion Used for Transformer Thermal Impact Assessments

Task 5 of NERC's preliminary GMD Research Work Plan is to conduct additional research and analysis to assess the transformer thermal impact of the benchmark GMD event or other

[14] The *Screening Criterion for Transformer Thermal Impact Assessment* white paper was filed in this proceeding on January 21, 2015 with NERC's petition for approval of TPL-007-1. NERC filed a corrected version of this white paper on June 28, 2016.

[15] Order No. 830 at P 66.

realistic GMD events. This Task is intended to address the Commission's directive to "include further analysis of the thermal impact assessment qualifying threshold" of 75 A per phase and to "address the effects of harmonics, including tertiary winding harmonic heating and any other effects on transformers" in NERC's GMD research work plan.[16] NERC estimates that this Task would require 24 months to complete from start of work.

F. Task 6: Section 1600 Data Request

As noted in the Background section of this filing, the Commission issued two sets of directives in Order No. 830 in addition to the directives to conduct GMD research. First, the Commission directed NERC to revise Reliability Standard TPL-007-1 to, among other things, require the collection of GIC monitoring and magnetometer data "as necessary to enable model validation and situational awareness, including from any devices that must be added to meet this need."[17] Second, the Commission directed NERC to collect GMD monitoring data pursuant to its authority under Section 1600 of the NERC Rules of Procedure for the period beginning May 2013, including data existing as of that date and new data going forward, and to make that information available.[18]

Efforts are currently underway through Project 2013-03 Geomagnetic Disturbance Mitigation to address the Commission's directive to revise the TPL-007 standard to require the collection of GIC and magnetometer data. Task 6 of NERC's preliminary GMD Research Work Plan would build upon the work of the Project 2013-03 standard drafting team to develop the necessary guidance and technical guidelines to support a request for data or information under

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16 *Id*. at PP 67-68.

17 *Id*. at P 88.

18 *Id*. at P 89.

Section 1600 of the NERC Rules of Procedure.[19] In addition, this Task contains activities to identify and develop the information technology system(s) to support data collection, hosting, and access. NERC estimates that the activities of this Task, which focus on laying the groundwork for the Section 1600 request for data or information, would require approximately 12 months to complete from start of work.

Following the completion of this Task, NERC would then proceed with the posting and approval process set forth in Section 1600 of the NERC Rules of Procedure.[20] NERC plans to conduct outreach through the NERC GMD Task Force to determine the degree to which industry is following NERC's guidance and to identify whether and to what extent additional guidance or support is necessary. The eventual goal is to maintain a high-quality collection of GIC and magnetometer data for industry and research use.

G. Task 7: Geoelectric Field Evaluation and Calculation Tool

Task 7 of NERC's preliminary GMD Research Work Plan builds upon the other items in NERC's plan and is intended to improve scientific understanding and advance the models and tools available for modeling GIC. Task 7 would involve evaluating available tools for calculating geoelectric field from magnetic field data for a given earth conductivity structure and developing additional tools as necessary to meet the needs of the industry. This task would include work to address "whether additional realistic time series should be selected to perform assessments in order to capture the time series that produces the most vulnerability for an area," consistent with

[19] NERC's rules require that each proposed request for data or information include certain information, such as the data to be collected and how it will be used, how the data will be validated, who is obligated to respond, the due date, a description of restrictions on dissemination, and an estimate of the relative burden to respond to the request. *See* NERC Rules of Procedure § 1602, http://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx.

[20] NERC's rules require that the draft request be submitted to the Office of Electric Reliability for informational purposes and be posted for a 45-day public comment period prior to being submitted to the NERC Board of Trustees for approval. *See* id.

the Commission's guidance.[21] NERC estimates this Task would require approximately 24-36 months to complete from start of work.

H. Task 8: Improve Harmonics Analysis Capability

Task 8 of NERC's preliminary GMD Research Work Plan would focus on developing guidelines for harmonics analysis and developing tools for entities to use in performing system-wide assessment of GMD-related harmonics. The work under this Task would build upon the work in Task 5 and is intended to address the Commission's directive to address the effects of harmonics in NERC's GMD research work plan.[22] The effects of GMD-related harmonics on reliable operations are only beginning to be understood. Harmonics could cause protection system misoperations, result in damage to capacitor banks and other electrical equipment, or affect the operating temperature of transformers. The development of tools and accurate models would aid in understanding these potential effects and how they may best be mitigated. NERC estimates this Task would require approximately 24-36 months to complete from start of work.

I. Task 9: Harmonic Impact Studies

Task 9 of NERC's preliminary GMD Research Work Plan is intended to further understanding of the other effects of harmonics, including vibrational effects, on power system equipment such as transformers and generators. This Task contemplates testing of two transformers, one with no vibration issues and one with vibration issues. This work should

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21 *See* Order No. 830 at P 79, in which the Commission stated:

> In addition, the large variances described by [United States Geological Survey] in actual 3-D ground conductivity data raise the question of whether one time series geomagnetic field is sufficient for vulnerability assessments. The characteristics, including frequencies, of the time series interact with the ground conductivity to produce the geoelectric field that drives the GIC. Therefore, the research should address whether additional realistic time series should be selected to perform assessments in order to capture the time series that produces the most vulnerability for an area.

22 *See id*. at P 68 and *supra* Section III.E.

identify what, if any, future actions and research activities are needed to effectively mitigate identified risks. NERC estimates this Task would require approximately 24 months to complete from start of work.

IV. NEXT STEPS

Since the issuance of Order No. 830, NERC has worked diligently to address the Commission's GMD research directives by collaborating with EPRI, the NERC GMD Task Force, and the NERC technical committees to develop the preliminary GMD Research Work Plan described in this filing. The preliminary GMD Research Work Plan addresses each of the GMD-related research areas identified by the Commission in Order No. 830 with a specific and targeted set of GMD research activities that are at the forefront of GMD research. The preliminary plan provides a solid framework for improving understanding of the threats posed by GMDs and how they may be addressed effectively.

With the scientific and technical components of the plan now in place, NERC plans to shift its focus toward developing the administrative components of the plan. This includes developing the appropriate project administration and funding structures to support the completion of GMD research. NERC expects that this work, which is described below, will take approximately six months to complete. NERC commits to keep Commission staff apprised of the status of its efforts.

As the ERO, NERC possesses extensive expertise and experience in matters affecting the reliability of the North American BPS. As noted earlier in this filing, however, NERC does not currently possess the necessary scientific expertise to conduct the described GMD research activities in-house, nor does it count among its "core competencies" the ability to manage such a large and complex GMD research undertaking. To satisfy the Commission's directive, NERC would want to work with organizations that do possess the type of specialized scientific,

technical, and research project management knowledge and experience necessary to successfully manage and execute such a project. Therefore, over the next several months, NERC plans to continue work to identify opportunities to incorporate the contributions and leadership of outside organizations into the overall project plan. NERC plans to continue discussions with EPRI, which has provided key contributions and leadership to the development of the plan to date. NERC also plans to continue outreach with: (i) representatives from governmental agencies in the U.S., Europe, and Canada, such as the U.S. Geological Survey, National Aeronautics and Space Administration, the U.S. Department of Energy, the National Oceanic and Atmospheric Administration, the National Science Foundation, and Natural Resources Canada; (ii) researchers in academia, such as Oregon State University; (iii) vendors; and (iv) industry. The purpose of this outreach is to identify opportunities to build on existing GMD research work, identify opportunities for research synergies, develop an appropriate research management structure, and identify alternative sources of funding. In addition, NERC plans to conduct outreach with stakeholders to explore approaches for structuring the funding requirements of the plan, including identifying opportunities for sharing costs, research management alternatives, and leveraging research responsibilities.

NERC expects that these efforts, as well as the comments and Commission guidance received through this proceeding, would inform the scope and structure of NERC's final GMD Research Work Plan and NERC's funding responsibilities. Given these uncertainties, NERC has not included costs related to GMD research activities in its draft 2018 Business Plan and Budget.[23] Depending on the timing of the start of work, final project structure, and the extent of

[23] Final project funding requirements would be subject to approval through NERC's budget process. NERC's budget process is set forth in Section 1100 of the NERC Rules of Procedure. The draft 2018 Business Plan and Budget is available at: http://www.nerc.com/gov/bot/FINANCE/Pages/2018-NERC-Business-Plan-and-Budget.aspx.

NERC's funding responsibilities, NERC may need to prepare and seek approval for a supplemental GMD research budget that could include a request for a special assessment.

Looking ahead, NERC appreciates the Commission's willingness to be flexible regarding changes to the specific project tasks and timelines set forth in this filing as it works to develop the final plan.[24] NERC recognizes the importance of ensuring that work remains performed in a timely manner, but asks that the Commission recognize that this is a significant expansion of NERC's role and would require a substantial investment of time and costs. NERC may ultimately face resource constraints that limit its ability to ensure completion of the Tasks in the timeframe contemplated by the preliminary GMD Research Work Plan. For example, NERC may be unable to obtain adequate funding for GMD research in a given year due to other pressing reliability needs, or it may encounter issues locating research partners that both possess the necessary expertise and are available to assist in a given timeframe.

NERC would therefore welcome guidance from the Commission regarding the prioritization of the specific research activities directed in Order No. 830. If faced with resource constraints, NERC would plan to prioritize the completion of Tasks to improve the alpha and beta factors used in the TPL-007 benchmark GMD event; specifically, Task 1 (Further Analyze Spatial Averaging Used in the Benchmark GMD Event) and Task 3 (Improve Earth Conductivity Models for GIC Studies). NERC would welcome the Commission's feedback on this prioritization. In addition, NERC would welcome any guidance from the Commission on which research activities should be assigned a lower priority or whose completion be made contingent on resource availability (e.g., availability of outside funding). This information would be

[24] *See* Order No. 830 at P 81.

particularly helpful to NERC as it continues its work to develop the final plan and address the challenges that lay ahead.

V. CONCLUSION

NERC respectfully requests that the Commission accept this filing in accordance with its directive from Order No. 830.

Respectfully submitted,

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May 30, 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 the above-referenced proceeding.

Dated at Washington, D.C. this 30th day of May, 2017.

/s/ Lauren A. Perotti

Lauren A. Perotti
Counsel for North American Electric Reliability Corporation

Attachment 1

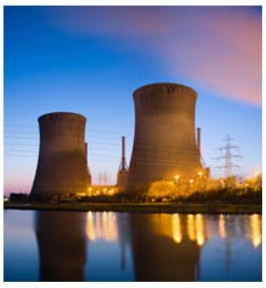
NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Order No. 830
GMD Research Work Plan

Addressing Geomagnetic Disturbance Events and Impacts on Reliability

PRELIMINARY PLAN
May 2017

RELIABILITY | ACCOUNTABILITY



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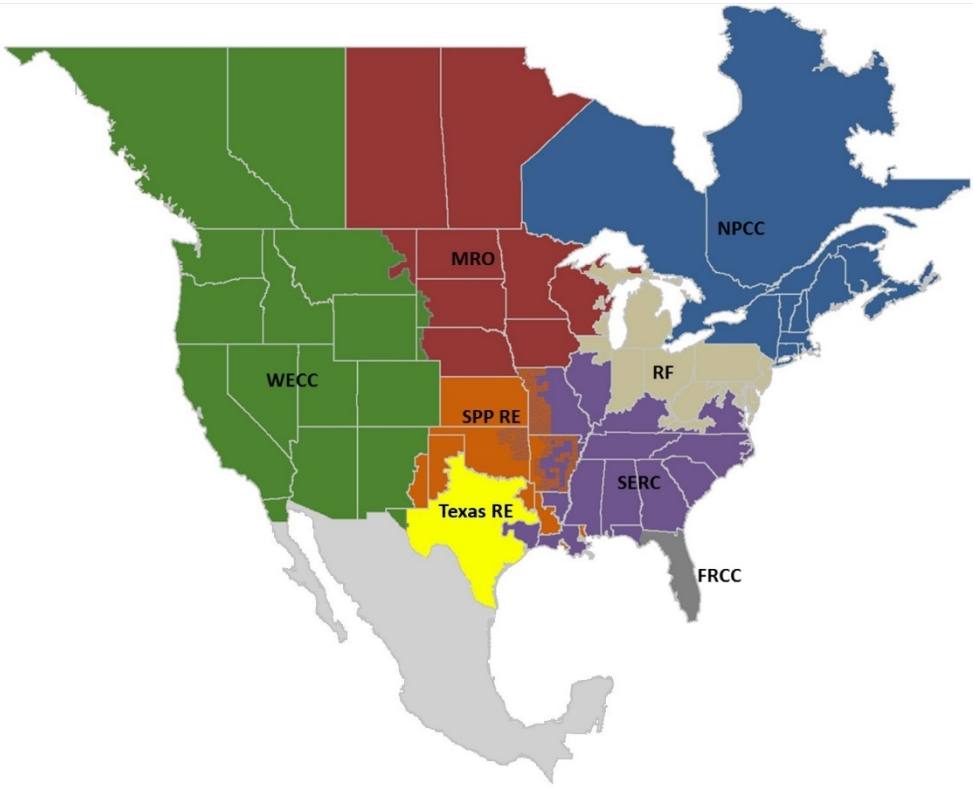
Preface

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

Introduction

Background

In Order No. 779,[1] FERC directed the development of Reliability Standards in two stages to address the potential impacts of geomagnetic disturbance (GMD) events on the reliability of the BPS. The first stage Reliability Standard, EOP-010-1 (*Geomagnetic Disturbance Operations*), requires owners and operators of the BPS to develop and implement operational procedures to mitigate the effects of GMDs consistent with the reliable operation of the BPS. This standard was approved by FERC in 2014.[2]

The second stage Reliability Standard, TPL-007-1 (*Transmission System Planned Performance for Geomagnetic Disturbance Events*), requires owners and operators of the BPS to conduct initial and ongoing assessments of the potential impact of a defined benchmark GMD event on BPS equipment and the BPS as a whole. FERC approved Reliability Standard TPL-007-1 in Order No. 830, issued on September 22, 2016.[3] FERC, however, directed NERC to develop certain modifications to the standard and undertake additional actions to further understanding of GMDs and their potential impacts on reliability.

Specifically, FERC directed NERC to:

- develop certain modifications to TPL-007-1, including: (i) revising the benchmark GMD event to not rely solely on spatially-averaged data; (ii) revising the standard to require entities to collect geomagnetically induced current (GIC) monitoring and magnetometer data as necessary to enable model validation and situational awareness; and (iii) revising the standard to include deadlines for the development and completion of any required Corrective Action Plans;[4]
- research specific GMD-related topics identified by the Commission and other topics in NERC's discretion, in accordance with a GMD research work plan filed with the Commission;[5] and
- collect GMD monitoring data pursuant to Section 1600 of the NERC Rules of Procedure and make that information available.[6]

This document addresses the second and third directives listed above. It sets forth a plan for driving research into the specific areas of GMD-related concern identified by the Commission and developing the framework to support a request for information under Section 1600 of the NERC Rules of Procedure. This preliminary work plan consists of the following nine research "Tasks":

1. Further Analyze Spatial Averaging Used in the Benchmark GMD Event
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 the 75 A per Phase Criterion Used for Transformer Thermal Impact Assessments
6. Section 1600 Data Request

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1 Order No. 779, *Reliability Standards for Geomagnetic Disturbances*, 143 FERC ¶ 61,147 (2013).

2 Order No. 797, *Reliability Standard for Geomagnetic Disturbance Operations*, 147 FERC ¶ 61,209, *reh'g denied*, Order No. 797-A, 149 FERC ¶ 61,027 (2014).

3 Order No. 830, *Reliability Standard for Transmission System Planned Performance for Geomagnetic Disturbance Events*, 156 FERC ¶ 61,215 (2016), *reh'g denied*, Order No. 830-A, 158 FERC ¶ 61,041 (2017).

4 *See* Order No. 830 at PP 44, 65, 88, and 101-102.

5 *See generally* id. at P 77.

6 Id. at PP 89, 93.

7. Geoelectric Field Evaluation and Calculation Tool
8. Improve Harmonics Analysis Capability
9. Harmonic Impact Studies

Specific research activities and estimated completion timeframes for each of these Tasks are identified in the subsequent sections of this work plan.

NERC collaborated with the Electric Power Research Institute (EPRI) to develop the specific research activities in this preliminary plan. EPRI is a nonprofit corporation organized under the laws of the District of Columbia Nonprofit Corporation Act and recognized as a tax exempt organization under Section 501(c)(3) of the U.S. Internal Revenue Code of 1986, as amended. EPRI was established in 1972 and has principal offices and laboratories located in Palo Alto, California; Charlotte, North Carolina; Knoxville, Tennessee; and Lenox, Massachusetts. EPRI conducts research and development relating to the generation, delivery, and use of electricity for the benefit of the public. An independent, nonprofit organization, EPRI brings together its scientists and engineers as well as experts from academia and industry to help address challenges in electricity, including reliability, efficiency, health, safety, and the environment.

Task 1: Further Analyze Spatial Averaging Used in the Benchmark GMD Event

Summary

The research activities under this Task consist of performing further research and analysis on the use of spatial averaging in defining benchmark GMD events that entities use when conducting the GMD Vulnerability Assessments required by the TPL-007 standard.

Activities

Task 1A: Perform Research to Improve Understanding of Characteristics and Spatial Scales of Localized Geoelectric Field Enhancements Caused by Severe GMD Events

- The analysis includes detection of a large number (10-20) of localized extreme events and collection of both ground-based and space-based data around the times of the events.
  - The ground-based and space-based data will be combined to build a comprehensive view of the solar wind-magnetosphere-ionosphere dynamic conditions at the times of the events.
  - The combined data will provide specification of the geospatial processes associated with the enhancements. Special attention will be paid to understand the possible association between localized enhancements and magnetospheric substorms.
  - The research team will collaborate with international leading experts (residing at NASA Goddard Space Flight Center) on substorms to improve understanding of which substorm-processes can lead to extreme localization of geomagnetic field observations on the ground.
  - These assessments will allow better characterization of both spatial and temporal characteristics as well as local time and geomagnetic latitude distribution of the localized geomagnetic field enhancements. The new results will be reported and reviewed via a peer-reviewed publication and included in the technical report.
- Review technical basis of the NERC Benchmark GMD Event Description white paper (May 2016)[7] including supporting peer-reviewed papers.
  - The NERC Benchmark GMD Event Description white paper will be reviewed in the light of the latest scientific research on the extreme GMD events. The review will include assessment of both geological work in terms of ground conductivity analyses and geospatial analyses characterizing the external drivers of extreme GMD events. Based on the review, recommendations will be made for possible modification of the benchmark GMD event. The review will be documented and included in the technical report.
- Perform analysis of magnetometer data to characterize the spatial structure of GMD events.
  - Step 1 - Develop dataset for large GMD events across all available magnetometer stations and resolve differences in temporal resolution and data gaps.
    - The purpose of this effort is to assemble a comprehensive data set to support GMD analyses. Ideally, such a data set would feature high-time resolution data (10 s or better) with rigorous error correction and background removal.
      - This task is necessary because existing community-wide efforts that serve geomagnetic data need to be improved upon to meet all of the above criteria. Specifically, one geomagnetic

[7] *Benchmark Geomagnetic Disturbance Event Description,* NERC Project 2013-03 GMD Mitigation Standard Drafting Team (May 12, 2016), http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

data set provides error correction and background removal, but it provides data at too low of time resolution (60 s, with high-resolution data down sampled); and another geomagnetic data set provides data at its original time resolution, but it performs minimal error correction and no background removal. Moreover, existing collections are not comprehensive, and historical data from now defunct magnetometers is frequently absent. These additional data sources will be incorporated in the compilation whenever possible, conditioning and processing the data as necessary.

  - The newly developed database and derived products, including processed and corrected time series and application programming interface (API) for appropriate software packages (e.g., MATLAB) and computer languages (e.g., Python), will be made available and documented in the technical report.

- Step 2 - Explore scaling of maximum E-field versus magnetic time of day.
  - The purpose of this effort is to characterize and quantify how the severity of GMD events depends on the magnetic time of day (MTOD). The data used in this study will be derived from the database compiled in the previous step. Magnetic fields will be converted to geoelectric fields using magnetotelluric methods (based on 1D conductivity profiles, comparing results to those from 2D impedance matrices when available).
  - Geoelectric field values will be processed in two different ways: 1) data from individual magnetometer sites will be analyzed using extreme value theory and the results of those studies will be binned by MTOD; and 2) data from all magnetometer sites will be binned by MTOD and extreme value analysis will be applied to the aggregate data set. The predictions of these complementary analyses will provide both a consistency check and an uncertainty estimate.
  - The results of the extreme value analysis will be used to develop a new statistical model of how geoelectric field magnitudes vary with MTOD. Because longitudinal data coverage is frequently very sparse, this model will allow for better application of latitudinal scaling when nearby reference measurements are unavailable.
  - Results from this work will be presented in a technical report describing a new MTOD scaling, analogous to the existing latitudinal scaling, along with a technical description of analysis methods.
- Step 3 - Compute the spatiotemporal autocorrelation in dB/dt and determine the characteristic time and length scales for variations in dB/dt.
  - The purpose of this work is to improve understanding of the extent to which localization (in space and time) affects the ability to predict geomagnetic fields at sites where measurements are unavailable. Data for this research effort will be obtained from the database compiled in a previous step. Using this data, the relationship between dB/dt and its individual frequency components at different spatial locations will be characterized. Correlations between time, frequency, magnetic latitude, and MTOD using both pairwise correlations and multivariate approaches such as multiple regression analysis will be investigated. Ultimately, this research will determine the appropriate spatial and temporal correlation parameters to inform Markov chain models of geomagnetic fields, which form the basis for developing a more sophisticated representation of the spatiotemporal behavior of geo-electric fields to better inform power systems GIC analysis.
  - The deliverable of this research will be a report (included in the technical report) describing the spatial and temporal scales (i.e., distances and durations) affected by GMDs as a function of geomagnetic latitude, MTOD, and frequency.

- Step 4 - Develop Markov chain models for generating spatiotemporal behavior of defined GMD events.
  - The purpose of this work is to develop a tool for building credible models of extreme GMD events based on historical data. Data from the database developed in Step 1 will be used to develop a Markov chain model that ingests data from historical events and produces new scenarios, which are consistent with the statistics of the original events. Ensembles of these synthetic events can be used to assess the potential vulnerability of systems to different spatial and temporal distributions of statistically identical GMDs, providing a means to credibly quantify the range of potential system effects due to disturbances of a given severity.
  - A product of this proposed research will be a software-based tool for scenario generation with APIs for appropriate software packages (e.g., MATLAB) and programming languages (e.g., Python), along with a detailed report describing the modeling techniques and software interfaces. This report will be included in the technical report.

- Perform magnetohydrodynamic (MHD) simulations and other analysis to improve understanding of localized geoelectric field enhancements.
  - The research will build on the simulations carried out by Ngwira, et al. (2013; 2014)[8,9]. New simulations will be carried out to study geospatial dynamics specifically associated with the localized geomagnetic field enhancements. Targeting of the localized enhancements will necessitate high spatiotemporal resolution simulations with careful attention to magnetotail dynamics, which are currently thought to be the geospatial origin of the localization seen on the ground. High-resolution simulations and associated processes in the magnetotail will be mapped into the ionosphere to look for signature that ultimately cause the localized magnetic field perturbations on the ground. The new results will be reported and reviewed via a peer-reviewed publication (and included in the technical report).

Task 1B: Determine the Impacts of Spatial Averaging Assumptions on the Bulk-Power System (BPS)

- Perform GIC, transformer thermal assessment and power flow analysis of North American regions to determine the effects of spatial scales of localized geoelectric field enhancements (e.g., 100 km x 100 km, 200 km x 200 km).
  - This task is to further analyze the area over which spatial averaging should be used in stability studies and transformer thermal assessments by performing GIC analysis on squares less than 500 km per side (e.g., 100 km, 200 km) and using the results to perform power flow and transformer thermal assessments.
  - This task will include the results from Task 1A to determine the enhanced electric field strength levels to be included in the localized geoelectric field enhancements.
  - A sliding window of varying areas (squares less than 500 km per side e.g., 100 km, 200 km per FERC Order No. 830) will be used over a model of the bulk power system to model the localized geoelectric field enhancements. This analysis will be conducted in a commercially available software package that is commonly used in the industry to study GIC flows in the bulk power system.

[8] C. Ngwira et al., *Simulation of the 23 July 2012 Extreme Space Weather Event: What if This Extremely Rare CME was Earth Directed?*, 11 SPACE WEATHER 671 (2013).

[9] C.M. Ngwira et al., *Modeling Extreme 'Carrington-type' Space Weather Events using Three-dimensional Global MHD Simulations*, 119 J. OF GEOPHYSICAL RES.: SPACE PHYSICS 4472 (2014).

- Using the calculated GIC values, perform transformer thermal assessment of North American regions to determine the effects of scales of localized geoelectric field enhancements. The thermal impact assessment will be based on published information[10,11] and documented accordingly.
- Using the calculated GIC values, perform a power flow (voltage stability) assessment of North American regions to determine effects of scales of localized geoelectric field enhancements (e.g., 100 km x 100 km, 200 km x 200 km).
- The results of this study will provide guidance to entities on applying spatially averaged and non-spatially averaged peak geoelectric field values, or some equally efficient and effective alternative, when conducting thermal impact assessments and power flow analysis. This guidance will be documented in the technical report.

Expected Deliverable

Technical Report

Estimated Time for Completion

24-36 months from start of work

[10] *See, e.g.*, IEEE, *Guide for Establishing Power Transformer Capability While Under Geomagnetic Disturbances*, IEEE Standard C57.163-2015 and EPRI, *Magnetohydrodynamic Electromagnetic Pulse Assessment of the Continental U.S. Electric Grid: Geomagnetically Induced Current and Transformer Thermal Analysis* (2017). 3002009001.

[11] *Transformer Thermal Impact Assessment* white paper, NERC Project 2013-03 Geomagnetic Disturbance Mitigation (May 2016), http://www.nerc.com/pa/Stand/Pages/Project-2013-03-Geomagnetic-Disturbance-Mitigation.aspx.

Task 2: Further Analyze Latitude Scaling

Summary

The research activities under this Task include evaluating the latitude scaling factors in Reliability Standard TPL-007-1, including using existing models and developing new models to extrapolate, from historical data, the potential scaling of a severe, 1-in-100 year event on lower geomagnetic latitudes.

Activities

- Perform review of peer-reviewed research (updated since the publication of the Benchmark GMD Event Description white paper) regarding the effects of geomagnetic latitude on geoelectric fields (based on a reference earth model).
  - This task will include an in-depth review of the newly-published work (e.g., by United States Geological Survey (USGS) and Los Alamos National Laboratory (LANL)), on geomagnetic latitude scaling. The review will include discussions with the researchers that published the works to find out if modifications are needed to the scaling factors in the Reliability Standard TPL-007-1.
  - This review will include recommendations for further actions and will be documented in the technical report.
- Determine which space weather indices are most effective in predicting latitude scaling of the maximum local geoelectric fields using current methods for conditioning magnetometer statistics. Extrapolate scaling to different benchmark event magnitudes.
  - The purpose of this work is to determine the best space weather index – or combination of indices – for predicting how maximum geoelectric fields scale with magnetic latitude. Ground-based magnetic field data for this investigation will be obtained from the database described in Step 1 of Task 1A: Further Analyze Spatial Averaging Used in the Benchmark GMD Event. Geomagnetic indices will be obtained from appropriate data providers, including the United States Geological Survey, the National Center for Environment Information, and the World Data Centers for Geomagnetism. This activity will use suitably-processed magnetometer data to estimate parameters of the latitudinal electric field profiles, and methods such as multiple regression analysis will be used to determine what index or combination(s) of indices most effectively predicts the latitudinal distribution of geoelectric fields.
  - A product of this research will be a report describing models, which are able to provide credible estimates of the geoelectric field profile along with a quantification of these models' uncertainties and an assessment of their potential ability to be used in an operational or predictive manner. This will be documented in the technical report.
- Perform analysis to provide additional technical support for existing latitude scaling factors or propose new values, as appropriate.
  - Understanding that no new observations of geomagnetic field variations are available for investigating the latitude scaling, state-of-the-art geospatial simulations can be used as a physics-based tool to investigate the processes that control the evolution of the auroral boundaries (i.e., the latitude scaling).
  - This task will include simulations with the latest updated models residing in the Community Coordinated Modeling Center (CCMC) to investigate the processes that control the propagation of the auroral boundaries toward more southern locations. The simulations will be conducted systematically using more extreme solar wind conditions as the driver and the response of the auroral boundaries will be recorded and investigated.

- A product of this research will be an establishment of the theoretical maximum limit for the auroral oval to expansion toward southern locations. Theoretical results will be analyzed in the observations-based latitude-scaling context to check if the two approaches (existing scaling factor and the new proposed scaling factor) converge toward the same scaling behavior.
    - The new results will be reported and evaluated via peer-reviewed publication and included in the final technical report.

Expected Deliverable

Technical Report

Estimated Time for Completion

24 months from start of work

Task 3: Improve Earth Conductivity Models for GIC Studies

Summary

The research activities under this Task consist of activities to improve the accuracy of existing earth conductivity models for GIC studies (TPL-007 beta scaling factor).

Activities

Task 3A: Use Magnetotelluric Measurement Data to Validate/Improve Existing Earth Conductivity Models Available to Industry and Researchers

- Compare the accuracy of 1D-earth conductivity models to 3D-earth conductivity models.
  - The goal of this activity is to compare electric fields derived from 1D earth conductivity models to those obtained from 3D Electromagnetic Transfer Functions (EMTFs).[12] In this activity, the 3D response will be used as the "ground truth," representing the realistic earth response to a geomagnetic storm. Work includes evaluating the ability of the 1D model to represent the average response over a given physiographic region to determine where 3D models are necessary and to validate the 1D model's effectiveness for GIC estimation. The following steps will be performed:
    - Step 1 - Compare the electric field response over each physiographic region using both 1D and 3D models for the extreme event scenario, where 3D data exist. Using the peak electric field metric, the 1D electric field to the average 3D response over the same region will be compared. This will be repeated for large historical events if time allows.
    - Step 2 - Identify regions where the 1D assumptions break down by using the differences in field orientation between 1D and 3D results. Also, identify 3D regions that may be too small in spatial extent to impact the average response over a larger region. Consider differences between 1D and 3D for the entire spectral response, as well as peak intensity.
    - Step 3 - Using the results obtained in Step 1; modify the 1D models as required to make them more accurately reflect the average 3D response. In some areas, sub-regions may be identified, and new or "effective" 1D models produced. Because these changes are frequency-sensitive, validation with other historical events will be needed.
    - The following will be provided in the technical report as a result of this research task:
      - A NERC operating area map of the differences between the 3D EMTF and the 1D electric field response for the extreme event scenario (intensity and direction).
      - Modified 1D models for all physiographic regions where changes are deemed necessary.
      - A NERC operating area map identifying regions of 1D and 3D validity, based on potential for geoelectric field rotation.

Task 3B: Develop Guidance for Validation of GIC Models

- Develop techniques and guidelines for using GIC and magnetometer data to perform model validation.
  - When performing a GMD analysis, it is typical to calculate an estimated GIC and compare to a measured GIC. This connects the source (geomagnetic field) with the response (induced current). There is the potential for large sources of error in several steps of this process: magnetic field input, earth conductivity models, dc system models, and the GIC data itself. The goal for this activity is to

[12] For example, SPUD EMTF – IRIS, http://ds.iris.edu/spud/emtf.

provide guidance for identifying and reducing these sources of error. The following steps will be performed:

- Step 1 - Evaluate GIC data sets to determine best practices for time cadence, data quality and archiving techniques.
- Step 2 - Assess the impact of magnetometer distance by calculating the electric field at a source location and correlating with the GIC response at increasing distances. Improve this by estimating GIC response using a realistic system model, if available.
- Step 3 - Test the assumptions by "degrading" the magnetometer signal and using different values of conductivity from the error range.
- The following will be provided in the technical report as a result of this research task:
  - A report documenting recommendations on the impact to the GIC estimate of magnetometer distance and conductivity model selection.
  - Error estimates versus distance to magnetometer.

Task 3C: Non-uniform Field Modeling

- A realistic geoelectric field during a geomagnetic event is non-uniform due to spatial variations in both the earth conductivity and the geomagnetic field source. The goal of this activity is to evaluate the impact of non-uniformities on GIC estimates and develop methods and models to handle these effects.
  - Assess the "coastal effect" and develop models to capture its effects.
    - One of the most important 3D effects is the enhancement and rotation of the electric field along coastal boundaries. Where 3D EMTFs are available, the exact electric field enhancement for a given storm can be determined. In other cases, available 1D conductivity models, existing methods in geophysics literature and publicly available bathymetry data must be used to estimate the potential coast effect. The following steps will be performed to produce a frequency dependent coast model:
      - Step 1 - Calculate the geoelectric field using 3D EMTFs and the extreme storm scenario.
      - Step 2 - Plot the estimated geoelectric field response vs distance from the coast.
      - Step 3 - Use the published approximations to determine first order theoretical inland effective distances, by frequency.
      - Step 4 - Use available open source tools and bathymetry maps to produce a first order 1D model of coast effects. This will be a map of the enhancement factor by distance from the coast, for a set of characteristic frequencies.
  - Develop standardized methods or models for capturing non-uniform geoelectric fields. Develop models to assess GIC simulation tools against non-uniform fields and compare GIC calculations for 3D and 1D ground conductivity models.
    - Step 1 - Select several examples of areas where electric field results show local enhancements due to 3D conductivity effects.
    - Step 2 - Calculate the electric field using 1D and 3D models.
    - Step 3 - Estimate GIC using these electric field inputs and compare them to GIC measurements, where possible.

  - Step 4 - Modify size of region and size of localized enhancement and rerun analysis to determine impact of changes.
- As a result of this research the following will be provided in the technical report:
  - First order coast effect model.
  - Guidance on the impact of non-uniform electric fields on GIC estimation.

- Establish a working group to promote the adoption including modeling of non-uniform geoelectric fields (including coastal effect) in commercially available software tools.

Expected Deliverable

Technical Report

Estimated Time for Completion

24-36 months from start of work

Task 4: Study GIC Field Orientation for Transformer Thermal Impact Assessments

Summary

This Task will develop an approach for applying the benchmark geoelectric field time series to individual transformers in thermal impact assessments. The research activities under this Task will consist of evaluating the existing approach used to perform transformer thermal assessments, and if deemed deficient, develop alternative methods of applying the benchmark geoelectric field time series to individual transformers to represent worst-case hot-spot heating conditions in transformer thermal impact assessments.

Activities

- Determine how the benchmark geoelectric field wave shape can be applied to individual transformers to determine worst-case hotspot heating.
  - Step 1 - Calculate GIC (t) using the Benchmark geoelectric field time series and steady state GIC results for a specified field orientation (worst case) using the methodology provided in TPL-007-1 and supporting documentation. Using GIC (t), compute the time series hotspot temperature, θ (t), using the procedure described in TPL-007-1 and supporting documentation.
  - Step 2 - Repeat the previous procedure for various other field orientations (e.g., 0°, 10°, 20°, 180°), and compare the resulting hotspot temperatures, θ (t), for each orientation.
  - Step 3 - If the worst-case hotspot heating is not generated by the electric field orientation that results in the maximum steady-state GIC flow in the transformer, evaluate other methods including, but not limited to, phase shifting the benchmark geoelectric field time series, such that the resulting GIC(t) yields the worst-case hotspot heating conditions.
  - The following will be documented in the technical report and entities will be able to:
    - Evaluate the potential effects of non-uniform geoelectric fields on the thermal assessment approach presented in TPL-007-1 and supporting documentation; and
    - Identify and quantify potential sources of error that can occur.

Expected Deliverable

Technical Report

Estimated Time for Completion

10-12 months from start of work

Task 5: Further Analyze the 75 A per Phase Criterion Used for Transformer Thermal Impact Assessments

Summary

Conduct additional research and analysis to assess transformer thermal impact of the benchmark GMD event or other realistic GMD events.

Activities

- The research activities under this Task consist of evaluating the existing 75A per phase criterion based on IEEE C57.163-2015[13] and if deemed deficient, develop alternative criteria. Recent research conducted as part of EPRI's electromagnetic pulse research will be leveraged in this task[14].
  - Step 1 - Evaluate the existing temperature limits used in TPL-007-1 and evaluate the potential for using other temperature limits based on various transformer conditions and other factors.
  - Step 2 - Determine the effects of short-term harmonic currents resulting from part-cycle saturation on tertiary winding heating. This will be accomplished by developing electrical models of typical high-voltage autotransformers with tertiary winding and generator step-up units that are suitable for estimating the flow of harmonic currents in the delta connected windings that are the result of part-cycle saturation. The models will be examined using various levels of GIC, and the additional hotspot temperature rise due to the flow of harmonic currents will be estimated. An analysis will be performed to determine the potential impact of this additional hotspot heating on the performance of the transformer.
  - Step 3 - Additional time-domain transformer thermal modeling parameters (asymptotic behavior and thermal time constants) will be developed for various transformer types and designs. Modeling parameters will be extracted from simulation results provided by transformer manufacturers and field/laboratory test results (if available). The results of the thermal models provided by the transformer manufacturer will be validated using field/laboratory test data where available.
  - Step 4 - Additional transformer thermal analyses will be performed to assess the efficacy of the existing 75 A/phase criteria. The basis of new current limits may be established based on the full spectrum of available transformer thermal models and the additional temperature limits developed as a part of this research task.
  - Based on the above analysis, the technical report will include:
    - The basis of new current limits if established based on the full spectrum of available transformer thermal models and the additional temperature limits developed in the above steps.
    - Additional transformer modeling parameters (e.g., asymptotic behavior and thermal time constants) will be included in a technical report.

Expected Deliverable

Technical Report

[13] IEEE, *Guide for Establishing Power Transformer Capability While Under Geomagnetic Disturbances,* IEEE Standard C57.163-2015.

[14] *Magnetohydrodynamic Electromagnetic Pulse Assessment of the Continental U.S. Electric Grid: Geomagnetically Induced Current and Transformer Thermal Analysis*. EPRI, Palo Alto, CA: 2017. 3002009001.

Estimated Time for Completion

24 months from start of work

Task 6: Section 1600 Data Request

Summary

The activities under this Task consist of developing the necessary guidance, technical guidelines, and solutions to support a request for data or information under Section 1600 of the NERC Rules of Procedure for the collection of GIC data and magnetometer data. In Order No. 830, FERC directed NERC, pursuant to Section 1600 of the NERC Rules of Procedure, to collect GIC monitoring and magnetometer data from registered entities for the period beginning May 2013, including both data existing as of the date of the Order and new data going forward.[15] Furthermore, FERC directed that NERC should make the collected GIC and magnetometer data available to support ongoing research and analysis of GMD risk.[16]

The data are intended to promote greater understanding of GMD events and their potential impacts to reliable operations. For example, measured GIC and magnetometer data can help validate various models used in calculating GICs and assessing their impacts in power systems.

Various entities, including some Transmission Owners, Generator Owners, Transmission Planners, and Planning Coordinators, collect GMD data and may have GMD data for the period beginning in May 2013. The data request would apply to entities that have the specified GMD data.

Activities

Develop guidance for the measurement of GIC and geomagnetic fields and formatting requirements for supplying measurement data and technical guidelines.

- A number of utilities have installed GIC monitoring equipment (e.g., participants in EPRI SUNBURST research project), which measure, acquire, and transmit GIC data to database which can be used for situational awareness and model validation. Additionally, some utilities have installed magnetometers. Guidance developed in this task will help entities plan for installing GIC monitoring and magnetometers. For example:
  - **Monitor locations.** When planning for new or 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 near 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 entity operating processes. 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.
  - **Magnetometers.** Entities that install magnetometers should consider equipment specifications and data format protocols contained in the latest version of the Intermagnet Technical Reference Manual.

[15] Order No. 830 at P 89. FERC clarified that this directive would not apply to non-U.S. responsible entities, or Alaska and Hawaii. *See id*. at n. 118.

[16] Order No. 830 at P 93 ("The record in this proceeding supports the conclusion that access to GIC monitoring and magnetometer data will help facilitate GMD research, for example, by helping to validate GMD models."). FERC clarified that "if GIC monitoring and magnetometer data is already publicly available (e.g., from a government entity or university), NERC need not duplicate those efforts." *See id*. at n. 122.

- Guidance to inform criteria for when entities should obtain data for future GMD events. For example:
  - Kp threshold (warning or attained).
  - Space weather alert indicating GMD commencement.
  - GIC threshold (dc measurement of current in the transformer neutral).
- Guidance to inform criteria that will promote data standardization and usability for model validation purposes. For example:
  - **Data format.** Greenwich Mean Time (GMT) (MM/DD/YYYY HH:MM:SS) time stamp and GIC Value (Ampere). Positive (+) and negative (-) signs indicate direction of GIC flow (Positive reference is flow from ground into transformer neutral). Time fields indicate the sampled time rather than system or SCADA time.
  - **Sampling Interval.** Data sampling during periods of interest at a continuous rate of 10 seconds or faster.
  - **Collect time-series data.**
- Guidance to inform development of information technology systems for data collection, hosting, and access.
  - The data request will specify methods for providing data to the NERC database (for example, email data files, upload to site using file transfer protocol (FTP)).

Expected Deliverables

Criteria to Support a Request for Data or Information under Section 1600 of the NERC Rules of Procedure
GIC/Magnetometer Specification, format for data request, and IT infrastructures to store the data

Estimated Time for Completion

12 months from start of work

Task 7: Geoelectric Field Evaluation and Calculation Tool

Summary

The activities under this Task consist of evaluating available tools for calculating geoelectric fields from magnetic field data for a given earth conductivity structure and developing additional tools as necessary to meet the needs of the industry.

Activities

- Evaluate publicly available software tools for calculating geoelectric field from magnetic field data for given earth conductivity structure.
  - The goal of this Task is to review all publicly-available tools for calculating geoelectric field data for a given earth conductivity structure and use this review to leverage the development of the following Task, which is to develop an open source tool capable of performing geoelectric field calculations using 1-D and 3-D layered earth model and time series geomagnetic data.
- Develop an open source tool capable of performing geoelectric field calculations using 1-D and 3-D layered earth model and time series geomagnetic data.
  - Step 1 - Develop a set of codes that can be used by utility analysts for GMD planning, including documentation and examples.
  - Step 2 - Include the option of using 1D layered earth conductivity models or a 3D EMTF.
- Perform time series simulations with improved 1D and 3D conductivity models to evaluate the earth conductivity (beta) scaling factors.
  - The goal is to improve the conductivity beta scaling factors and make some error estimates to guide their use. Improved conductivity models will be used to improve the scaling ratio calculation by looking at the entire spectral response instead of the ratio of one spectral component. This analysis will involve the following steps:
    - Step 1 - Choose several geomagnetic field time series as sources. Examples include the extreme storm scenario, some data from the recent historical record, and selected storms with different frequency content. An additional option is to use artificially constructed magnetic spectra with different characteristics to test the error bounds of the scaling factors.
    - Step 2 - Use the same "baseline" as the original beta factor calculations. Calculate the peak geoelectric field for each magnetic storm input using the 1D Canadian Shield (Quebec) earth conductivity model.
    - Step 3 - For each location/conductivity model, and for each input time series, calculate the peak electric field ratio: max (E_location)/max (E_CanadianShield).
    - Step 4 - For each set of results from Step 3, determine the beta factor, and the error bars for each location.
  - As a result of this research, the following will be delivered in the technical report:
    - Map of improved beta factors based on updated conductivity profiles, with error bars.

Expected Deliverables

Technical Report
Open Source Software Tool

Estimated Time for Completion

24-36 months from start of work

Task 8: Improve Harmonics Analysis Capability

Summary

The activities under this Task consist of developing harmonics analysis guidelines and tools for entities to use in performing system-wide assessment of GMD-related harmonics. GMD-related harmonics are caused by the part-cycle saturation of transformers. The harmonic currents and voltages resulting from transformer saturation have had major impacts on system operations and security during severe GMD events in the past.[17] Harmonics studies are an integral part of any GMD Vulnerability Assessment, and as such, are a key component of related reliability and planning assessments and associated regulatory requirements.

Performing harmonic analysis is difficult, and to date, the commercially available frequency-domain tools do not adequately address nuances of performing GMD-related harmonics studies. For example, there are some important difficulties and modeling gaps that need to be addressed before the harmonic impacts of a GMD event can be accurately assessed. Such difficulties and gaps include (but are not limited to):[18]

- The effective GIC flow in all transformers in the network must be known beforehand, and mapping between GIC and the harmonics that are created is required.
- The magnitude and phase angle of the injected harmonic currents of each transformer is affected by local voltage distortion; thus, an iterative technique must be employed.
- The complex interaction of magnitude and phase angles of the injected harmonic currents of multiple transformers must be taken into account.
- Because part-cycle saturation creates zero sequence harmonics, standard positive sequence power flow data cannot be used alone as a basis for assembling the system model.
- Harmonic resonance created by shunt capacitor banks, and the damping effect of loads must be considered.

Activities

- Step 1: Perform research necessary to develop models and methods to improve capability of performing harmonic assessments of GMD events. Initial focus will be on developing frequency-domain transformer models that can be used in GIC-integrated harmonics studies.
- Step 2: based on the research conducted in Step 1, an accurate GMD harmonic analysis approach will be developed using proper consideration of the closed-loop interactions between the harmonic current injections by the saturated transformers and the voltage distortion that these injections cause.
- Step 3: based on the results of Step 1 and 2, a frequency-domain based harmonic GMD analysis tool will be developed. Included in this development, a GMD system model will be created to accurately assess and verify both time-domain models and the newly developed frequency-domain models. This will provide confidence in the frequency-domain models that are developed as a part of this research Step.
- Step 4: All models and techniques developed as a part of this research will be implemented in an open source software tool. This tool will be used to:
  - Aid system planners in evaluating impacts of harmonics on reactive power resources (e.g. shunt capacitor banks, static var compensators, etc.); and

[17] NERC, *March 13, 1989 Geomagnetic Disturbance* white paper, http://www.nerc.com/files/1989-quebec-disturbance.pdf.

[18] EPRI, *Analysis of Geomagnetic Disturbance (GMD) Related Harmonics* (2014). 3002002985.

  - Facilitate the implementation of GMD harmonic assessments in commercially available software tools.
- Additionally, a harmonics modeling workshop will be conducted to facilitate knowledge transfer.
- Harmonics assessment tools will be validated with available GIC data as part of software and model validation.
- The deliverables from this task would be open source harmonics assessment software/tools and a technical report on harmonics analysis guidelines.

Expected Deliverables

Report
Open Source Software Tool

Estimated Time for Completion

24-36 months from start of work

Task 9: Harmonic Impact Studies

Summary

The activities under this Task consist of activities to understand the impacts of harmonics on power system equipment. The Task will address the adverse impacts to transformers and generators caused by harmonics associated with GMD events. This Task responds to FERC's direction to address the effects of harmonics on transformers. The impacts of transformer heating are covered in detail in Tasks 4 and 5 of this plan. This section will focus mainly on the impacts of vibrations on power transformers.

Activities

- Transformer harmonic assessment:
  - Step 1 – Research and report on all available data (including published industry and EPRI documents and available transformer manufacture test data) on the following topics:
    - Typical tank vibration levels and frequency spectrum in absence of GIC. This information would be used to develop a baseline of tank vibration levels and frequency spectrum. The following would be included in this sample:
      - Transformers with no vibration issues (e.g., new construction).
      - Transformers with vibration issues (e.g., existing construction that may have existing loose hardware).
    - Impact of GIC on transformer noise. This information would be used to compare against a baseline of tank vibration levels and frequency spectrum.
      - Theoretical impact of GIC on core noise (analysis to be verified by testing) on transformer noise level and frequency spectrum.
    - Examples of measured impact of GIC on core noise.
      - Correlation between calculated and measured impact of GIC on core noise (i.e., correlation with neutral GIC and correlation with effective GIC).
    - Documented in the technical report will be recommendations on the feasibility of using tank vibration measurements to monitor impacts of GIC on transformers and impact of vibrations due to GIC on the integrity of transformers. This research will be needed to provide guidance in real-time monitoring to protect transformers against vibration damage caused by GIC.
    - Identify areas for future study.
  - Step 2 - Perform transformer tank vibration measurements on two (2) transformers when subjected to GIC. Testing to be conducted in a laboratory environment.
    - Compare measurements to the theoretical relationship between tank vibrations and level of GIC.
    - Develop expected relationship between tank vibrations and level of GIC for higher levels of GIC.
    - Documented in the technical report will be the following:
      - Impact of higher tank vibrations due to GIC on integrity of power transformers.
      - Future actions and/or research activities needed.

- Generator harmonic assessment:
  - Step 1 - Perform assessment of harmonic effects on generators to improve understanding of gaps in existing Reliability Standards with harmonic levels that are unique to GMD events. This assessment will include all available published and existing EPRI research.
  - Step 2 - The generator harmonic assessment will use the system level harmonic modeling research results. The system level harmonic modeling will provide guidance for the level of expected GMD related harmonics that would be sourced from a generator.
  - Step 3 - Results from the harmonic tool can then be compared to published standards to better understand the problems that will result from generator harmonics.
  - Documented in the technical report will be:
    - The gaps in published standards that are unique to GMD events;
    - Potential issues that are already addressed in the standards; and
    - Future scoping and testing needs.

Expected Deliverable

Technical Report

Estimated Time for Completion

24 months from start of work

Estimated Project Costs

It is estimated that this plan would require, over a minimum three-year period, approximately $3 million to $3.5 million to complete, including costs for research and time and costs associated with identifying and developing information technology (IT) systems for hosting collected GMD data.

The estimated cost for the completion of the research activities (i.e., excluding IT costs) is approximately $2.72 million, as detailed in Table 1 below.

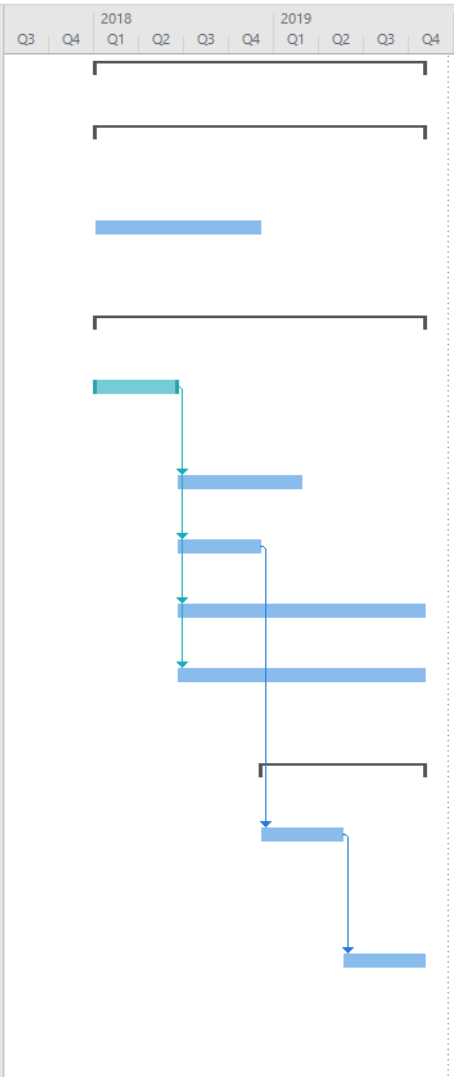
Table 1.1 Research and Development Costs, by Task (estimated)

Task	Topic	Time to Completion (from start of work)	Price
1	Spatial Averaging	24-36 months	$890,000
2	Latitude Scaling	24 months	$225,000
3	Earth Conductivity Models	24-36 months	$397,000
4	Geomagnetic Field Orientation	10-12 months	$50,000
5	Transformer Thermal Impact Assessment Criterion	24 months	$400,000 ($30k added per additional transformer model beyond 10)
6	Guidance and Guidelines to Support Section 1600 Data Request	12 months	$50,000
7	Geoelectric Field Evaluation and Calculation Tool	24-36 months	$305,000
8	Harmonics Analysis Capability	24-36 months	$200,000
9	Harmonic Impact Studies	24 months	$205,000
Total			**$2,722,000**

Project Schedule Example

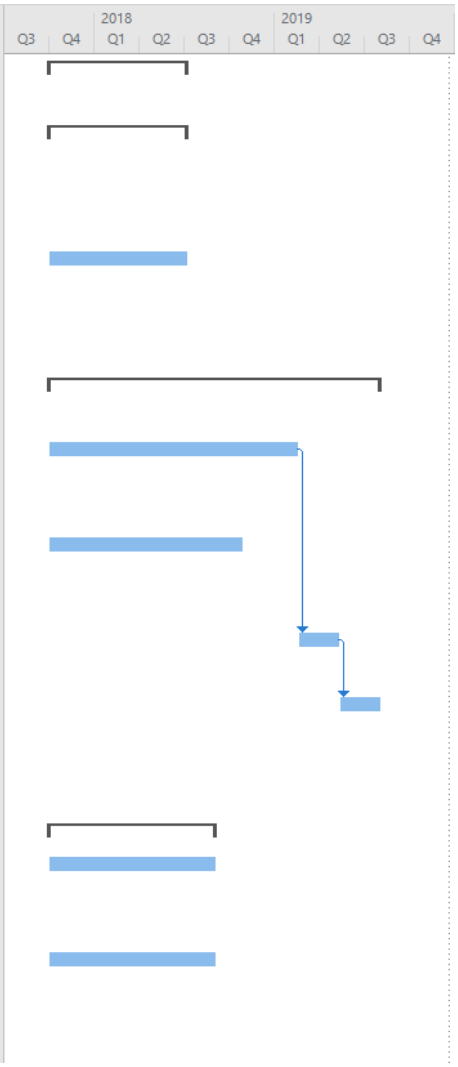
EPRI has provided the following as an example of a project schedule that shows the estimated timeframes for completing the research activities under each Task in the 2018-2019 timeframe.

Task Name	Duration	Start	Finish
TASK 1 - FURTHER ANALYZE SPATIAL AVERAGING USED IN THE BENCHMARK GMD EVENT	**480 days**	**Tue 1/2/18**	**Mon 11/4/19**
Perform research to improve understanding of the phenomenology and spatial scales of localized geoelectric field enhancements caused by severe	**480 days**	**Tue 1/2/18**	**Mon 11/4/19**
Review technical basis of the NERC Benchmark GMD Event Description white paper (May 2016) including supporting peer-reviewed papers.	12 mons	Tue 1/2/18	Mon 12/3/18
Perform analysis of magnetometer data to characterize spatial structure of GMD events	**480 days**	**Tue 1/2/18**	**Mon 11/4/19**
Develop "full" dataset for large GMD events across all available magnetometer stations. Resolve issues/differences in temporal	6 mons	Tue 1/2/18	Mon 6/18/18
Explore scaling of maximum dB/dt versus magnetic time of day (TOD).	9 mons	Tue 6/19/18	Mon 2/25/19
Compute the spatiotemporal autocorrelation in dB/dt. Determine the characteristic time and	6 mons	Tue 6/19/18	Mon 12/3/18
Develop Markov Chain Models for generating spatiotemporal behavior of benchmark events	18 mons	Tue 6/19/18	Mon 11/4/19
Perform magnetohydrodynamic (MHD) simulations and other analysis to improve understanding of the phenomenology of localized	18 mons	Tue 6/19/18	Mon 11/4/19
Determine impacts of spatial averaging assumptions on bulk-power system reliability.	**240 days**	**Tue 12/4/18**	**Mon 11/4/19**
Perform GIC and power flow analysis of various regions within North America to determine effects of spatial scales of localized geoelectric field enhancements, e.g. 100 km x 100 km, 200 km x	6 mons	Tue 12/4/18	Mon 5/20/19
Perform transformer thermal assessment of various regions within North America to determine effects of scales of localized geoelectric field enhancements, e.g. 100 km x 100 km, 200 km x	6 mons	Tue 5/21/19	Mon 11/4/19

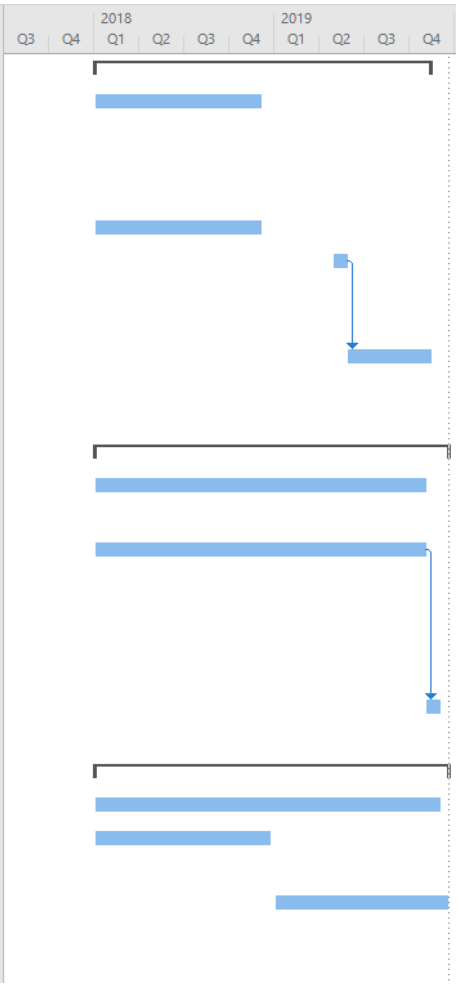


Task Name	Duration	Start	Finish
TASK 2 - FURTHER ANALYZE LATITUDE SCALING	**489 days**	**Tue 1/2/1**	**Fri 11/15,**
Perform review of peer-reviewed research (updated since publication of Benchmark GMD Event white paper) regarding the effects of geomagnetic latitude	12 mons	Tue 1/2/18	Mon 12/3/18
Using current methods for conditioning magnetometer statistics, determine which space weather indices (Dst, AE, etc....) are most effective in predicting the latitude scaling of the maximum local	12 mons	Tue 5/1/18	Mon 4/1/19
Perform analysis to provide: 1) additional technical support for existing latitude scaling factors or 2) propose updated values as appropriate.	19 mons	Mon 6/4/18	Fri 11/15/19
TASK 3 - IMPROVE EARTH CONDUCTIVITY MODELS FO	**480 days**	**Tue 1/2/1**	**Mon 11/4**
Use magnetotelluric (MT) measurement data to validate/ improve existing earth conductivity models.	12 mons	Tue 1/2/18	Mon 12/3/18
GMD Task force: guidelines for performing validation of GIC models	**480 days**	**Tue 1/2/18**	**Mon 11/4/19**
Develop techniques and guidelines for using GIC and magnetometer data to perform model	24 mons	Tue 1/2/18	Mon 11/4/19
Non-uniform Field Modeling	**480 days**	**Tue 1/2/1**	**Mon 11/4**
Assess coastal effect and develop models for accurately capturing its effects	24 mons	Tue 1/2/18	Mon 11/4/19
Develop standardized methods for modeling non-uniform geoelectric fields	24 mons	Tue 1/2/18	Mon 11/4/19
Develop benchmark models to assess GIC simulation tools against non-uniform fields	24 mons	Tue 1/2/18	Mon 11/4/19
Establish a working group to promote the adoption of modeling non-uniform geoelectric field (including coastal effect) into commercially available software tools	24 mons		

Task Name	Duration	Start	Finish
TASK 4 - STUDY WORST-CASE GEOMAGNETIC FIELD ORIENTATION FOR TRANSFORMER THERMAL	**200 days**	**Mon 10/2/17**	**Fri 7/6/18**
Perform analysis to evaluate the ability of GIC flow calculated as specified in TPL-007 to represent worst-case transformer hot-spot heating conditions for the Benchmark GMD Event or other	**200 days**	**Mon 10/2/17**	**Fri 7/6/18**
Determine how the benchmark geoelectric field wave shape can be applied to a particular transformer to determine worst-case hotspot heating.	10 mons	Mon 10/2/17	Fri 7/6/18
TASK 5 - FURTHER ANALYZE THE 75 A PER PHASE CRITERION USED FOR TRANSFORMER THERMAL	**480 days**	**Mon 10/2/17**	**Fri 8/2/19**
Conduct additional research and analysis to assess transformer thermal impact of the Benchmark GMD Event or other realistic GMD events.	18 mons	Mon 10/2/17	Fri 2/15/19
Perform research to determine the effects of short-term harmonic currents resulting from half-cycle saturation on tertiary winding heating.	14 mons	Mon 10/2/17	Fri 10/26/18
Evaluate the use of alternative performance criteria (e.g. the use of different temperature limits).	3 mons	Mon 2/18/19	Fri 5/10/19
Create additional thermal models (thermal response during heating and cooling, asymptotic behavior) and perform transformer thermal assessment using synthetic GIC.	3 mons	Mon 5/13/19	Fri 8/2/19
TASK 6 - DATA REQUEST COMMENSURATE WITH SECT	**240 days**	**Mon 10/2**	**Fri 8/31/1**
Develop a Section 1600 Data Request for the collection of existing and new GIC and Magnetometer data that can be made available to	12 mons	Mon 10/2/17	Fri 8/31/18
Develop guidance for the measurement of GIC and geomagnetic field and formatting requirements for supplying measurement data.	12 mons	Mon 10/2/17	Fri 8/31/18



Task Name	Duration	Start	Finish
TASK 7 - GEOELECTRIC FIELD CALCULATION TOOL	**486 days**	**Tue 1/2/1**	**Tue 11/1**
Evaluate available tools for calculating geoelectric field from magnetic field data for given earth conductivity structure, and develop additional tools as necessary to meet the needs of the industry.	12 mons	Tue 1/2/18	Mon 12/3/18
Perform assessment of commercially available tools.	12 mons	Tue 1/2/1	Mon 12/3
Develop open source tool capable of performing geoelectric field calculations using 1-D/3-D layered earth model and time series geomagnetic field data.	1 mon	Wed 5/1/19	Tue 5/28/19
Perform time-series simulations with improved 1D and 3D conductivity models to improve the beta factors (scaling factors to account for earth	6 mons	Wed 5/29/19	Tue 11/12/19
TASK 8 - IMPROVE HARMONICS ANALYSIS CAPABILIT	**514 days**	**Tue 1/2/1**	**Fri 12/20,**
Develop Harmonics Analysis guidelines; tools for system-wide assessment.	24 mons	Tue 1/2/18	Mon 11/4/19
Develop models and methods to improve capability of performing harmonic assessments of benchmark GMD events. Implement models and methods developed as a part of item 1 into an open source software environment (GIC integrated harmonics	24 mons	Tue 1/2/18	Mon 11/4/19
Hold a harmonics modeling workshop to facilitate knowledge transfer	1 mon	Tue 11/5/19	Mon 12/2/19
TASK 9 - HARMONIC IMPACT STUDIES	**514 days**	**Tue 1/2/1**	**Fri 12/20,**
Understand harmonics impacts on power system a	500 days	Tue 1/2/1	Mon 12/2
Perform transformer studies/ testing to quantify the impacts of vibrations due to GIC on the	254 days	Tue 1/2/18	Fri 12/21/18
Generator harmonic assessment	253 days	Wed 1/2/	Fri 12/20/



Next Steps

In the coming months, NERC will continue to explore ways to refine the plan based on feedback and will continue discussions with EPRI, industry, FERC, and other research partners to explore opportunities to leverage existing work, share project oversight and responsibilities, and establish a project schedule.

Final budget and funding mechanisms are subject to budget approval.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Reliability Technical Conference Docket No. AD17-8-000

SUPPLEMENTAL NOTICE OF TECHNICAL CONFERENCE

(May 19, 2017)

Take notice that the Federal Energy Regulatory Commission (Commission) will hold a Technical Conference on Thursday, June 22, 2017, from 9:30 AM to 4:30 PM. This Commissioner-led conference will be held in the Commission Meeting Room at the Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426. The purpose of the conference is to discuss policy issues related to the reliability of the Bulk-Power System. Attached is an agenda for this event.

The conference will be open for the public to attend. There is no fee for attendance. However, members of the public are encouraged to preregister online at: https://www.ferc.gov/whats-new/registration/06-22-17-form.asp.

Information on this event will be posted on the Calendar of Events on the Commission's website, http://www.ferc.gov, prior to the event. The conference will also be webcast and transcribed. Anyone with Internet access who desires to listen to this event can do so by navigating to the Calendar of Events at http://www.ferc.gov and locating this event in the Calendar. The event will contain a link to the webcast. The Capitol Connection provides technical support for webcasts and offers the option of listening to the meeting via phone-bridge for a fee. If you have any questions, visit http://www.CapitolConnection.org or call (703) 993-3100. Transcripts of the technical conference will be available for a fee from Ace-Federal Reporters, Inc. at (202) 347-3700.

Commission conferences are accessible under section 508 of the Rehabilitation Act of 1973. For accessibility accommodations, please send an email to accessibility@ferc.gov or call toll free 1 (866) 208-3372 (voice) or (202) 502-8659 (TTY), or send a fax to (202) 208-2106 with the required accommodations.

For more information about this conference, please contact:

Sarah McKinley
Office of External Affairs
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888 First Street, N.E.
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(202) 502-8368
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Kimberly D. Bose,
Secretary.

Reliability Technical Conference

Docket No. AD17-8-000

Thursday, June 22, 2017
9:30 a.m. – 5:00 p.m.

9:30 a.m. **Opening Remarks**

9:45 a.m. **Introductions**

10:00 a.m. **Panel I: Overview on the State of Reliability**

Presentations: As we consider the 2017 State of Reliability report recently issued by the North American Electric Reliability Corporation (NERC), panelists will be asked to address the following questions:

a. What trends and risks identified in the 2017 State of Reliability report warrant the most attention and effort at this time?

b. Data and data analysis are increasingly used to measure and assess the reliability of the Bulk-Power System. What are the gaps in our ability to measure system reliability, especially as the Bulk-Power System evolves?

c. What, if any, actions are needed to improve the reliability standards? What, if any, non-reliability standard actions should the Commission encourage or take on reliability? How has reliability improved as a result of applying the lessons learned from major events, such as the 2003, 2008, and 2011 blackouts? Are we appropriately taking into account lessons learned from other events and "blue-sky" operations to continuously improve reliability?

d. What are the implications of expanding distributed energy resources (DER) for the Bulk-Power System? What are the potential challenges and benefits of DER to the reliable operation of the Bulk-Power

System? For example, the Commission recently modified the *pro forma* Small Generator Interconnection Agreement to require newly interconnecting small generating facilities to ride through abnormal frequency and voltage events and not disconnect during such events. Recent events, such as disconnections of grid-connected solar resources resulting from the Blue Cut fire in California, have suggested that the methods or devices used by inverter-connected generation to monitor voltage and frequency may be of concern. Are the policies currently in place that direct the behavior of inverter connected generation adequate?

Panelists:

- Gerry Cauley, President and Chief Executive Officer, North American Electric Reliability Corporation
- Patricia Hoffman, Principal Deputy Assistant Secretary and Acting Assistant Secretary, Office of Electricity Delivery & Energy Reliability, U.S. Department of Energy
- Chairman Asim Haque of the Public Utilities Commission of Ohio, representing NARUC
- Terry Bassham, Chairman, President and Chief Executive Officer, Great Plains Energy and Kansas City Power & Light Company
- Steven Wright, General Manager, Chelan Public Utility District on behalf of Large Public Power Council
- Babak Enayati, Lead R&D Engineer, National Grid on behalf of IEEE
- John Twitty, Executive Director, Transmission Access Policy Study Group
- John Hughes, President & Chief Executive Officer, Electricity Consumers Resource Council

11:15 a.m. Panel II: International Perspectives

Presentations: Electric grids across the world are changing rapidly, given retirements of coal and nuclear generation, the addition of renewable and distributed generation, the decline in load growth, and increasing automation. In addition, countries around the world are introducing and expanding markets, improving transmission planning across international borders, and expanding pipeline infrastructure to facilitate additional gas-fired generation.

a. What measures is your country taking to address these types of changes?

b. How is your country implementing and managing distributed resources?

c. What have been the challenges under your regulatory scheme? How have you responded?

Panelists:

- Canadian representative (*Invited)*
- Commissioner Marcelino Madrigal, Mexican Energy Regulatory Commission
- Klaus Dieter Borchardt, Director for the EU Internal Energy Market, Directorate-General for Energy, European Commission

12:30 p.m. Lunch Break

1:30 p.m. Panel III: The Potential for Long-Term and Large-Scale Disruptions to the Bulk–Power System

Presentations: Large-scale and long-term disruptions to the Bulk-Power System have the potential to cause significant human and economic harm. The Commission is interested in discussing how to address new and emerging risks. Presenters will be asked to discuss the following:

a. Speakers discussed the loss of the Aliso Canyon gas storage facility in California at the 2016 Reliability Technical Conference. What has industry learned from this event and what mechanisms have been put into place to mitigate the impact of the reliance on a single gas storage facility? How have these lessons learned been applied to similar gas storage facilities and the increased dependence of the Bulk-Power System on natural gas across the country? How can the Commission better address the risks of fuel disruptions to the reliable operation of the Bulk-Power System and its ability to recover?

b. Hazards from a man-made electromagnetic pulse may have significant consequences on the Bulk-Power System. Discuss the research underway on these hazards and the current gaps in knowledge.

c. Are there other emerging hazards that could have severe and lasting impacts on the Bulk-Power System? What are the biggest issues industry could face when bringing back the Bulk-Power System from an extended blackout?

d. Grid resilience includes the ability to withstand and recover from deliberate attacks, accidents, or naturally occurring threats or incidents. Are there

steps the Commission should be taking to improve resilience? Does the grid need more hardening for severe weather or other threats?

Panelists:

- Mark Lauby, Senior Vice President and Chief Reliability Officer, North American Electric Reliability Corporation
- Dede Subakti, Director, Operations Engineering Services, California Independent System Operator
- Michael Kelly Rivera, Los Alamos National Laboratory
- Earl Gjelde, Commissioner, Commission to Assess the Threat to the United States from Electromagnetic Pulse Attack
- Randy Horton, Senior Program Manager at Electric Power Research Institute
- Marie Jordan, President and CEO, Peak Reliability
- Thomas Popik, Chairman and President, Foundation for Resilient Societies
- Sylvain Clermont, Director, Reliability Standards and Regulatory Compliance, Hydro-Québec TransÉnergie

3:00 p.m. Break

3:15 p.m. Panel IV: Grid Security

Presentations: Cybersecurity continues to be a rapidly evolving risk to the Bulk-Power System. CIP Reliability Standards are 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-Power System. The 2015 and 2016 cyber-attacks on the electric grid in Ukraine are examples of how cyber systems used to operate and maintain interconnected networks, unless adequately protected, may be vulnerable to cyber-attack.

a. While controls in the CIP Reliability Standards reduce the risk of cyber-attacks, additional controls or modifications may further mitigate potential impacts on the operation of the Bulk-Power System. Which controls have been most effective? Are there additional controls, modifications, or voluntary actions that should be considered to improve cybersecurity? What partnerships should the Commission form or strengthen to help improve the overall cybersecurity posture of the Bulk-Power System?

b. A system is only as secure as the people who run and operate it. What can the Commission do to facilitate or encourage a strong cyber workforce?

Panelists:

- Marcus Sachs, Senior Vice President and Chief Security Officer, North American Electric Reliability Corporation
- Manimaran Govindarasu, Professor of Computer Engineering, Iowa State University
- Michael Assante, Director Critical Infrastructure and Curriculum Lead for ICS/SCADA, SANS Institute
- Greg Ford, President and CEO, Georgia System Operations Corporation
- Bob Bradish, Vice President, Transmission Grid Development, American Electric Power Service Corporation
- Nathan Mitchell, Senior Director, Electric Reliability Standards & Security, American Public Power Association
- Commissioner Robert (Bob) Scott, New Hampshire Public Utilities Commission
- Brandon Wales, Director, Office of Cyber and Infrastructure Analysis, U.S. Department of Homeland Security

4:45 p.m. Closing Remarks

5:00 p.m. Adjourn

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD17-5-000

April 28, 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 Western Electricity Coordinating Council for Approval of Proposed Regional Reliability Standard VAR-501-WECC-3

Dear Mr. Elstein:

On March 10, 2017, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) filed a joint petition seeking approval of proposed regional Reliability Standard VAR-501-WECC-3. NERC and WECC also requested approval of the associated implementation plan for the proposed regional Reliability Standard, the associated violation risk factors and violation severity levels, and the retirement of regional Reliability Standard VAR-501-WECC-2. The proposed regional Reliability Standard establishes the performance criteria for power system stabilizers to help ensure the Western Interconnection is operated in a coordinated manner under normal and abnormal conditions.[1]

Proposed regional Reliability Standard VAR-501-WECC-3 includes requirements providing transmission operators with procedures or other documents that inform the transmission operator of when a power system stabilizer will be out of service; having the power system stabilizer in service at all times except during specific circumstances; tuning power system stabilizers to stated criteria; installing and completing start-up testing of a power system stabilizer; and repairing or replacing a power system stabilizer within a specified time period. NERC and WECC state that proposed regional Reliability

[1] Petition at 1.

Standard VAR-501-WECC-3 improves upon the existing regional Reliability Standard by focusing the in-service requirement on performance of the power system stabilizers rather than counting the hours they are online; incorporating the power system stabilizer policies and guidelines into a mandatory standard; and reducing administrative requirements with little benefit to reliability.[2]

NERC's and WECC's joint filing was noticed on March 20, 2017, with interventions, comments and protests due on or before April 19, 2017. No interventions, comments or protests were received.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2016), 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 (2016).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

[2] *Id.* at 3.

20170417-3001 FERC PDF (Unofficial) 04/17/2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD17-4-000

April 17, 2017

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Counsel for North American Electric Reliability Corporation

Reference: Petition of the North American Electric Reliability Corporation for Approval of Proposed Reliability Standards IRO-002-5 and TOP-001-4

Dear Mr. Elstein:

On March 6, 2017, the North American Electric Reliability Corporation (NERC) filed a petition for approval of proposed Reliability Standards IRO-002-5 (Reliability Coordination - Monitoring and Analysis) and TOP-001-4 (Transmission Operations). NERC states that the proposed Reliability Standards address the Commission's directives in Order No. 817[1] related to: (1) transmission operator monitoring of non-bulk electric system (BES) facilities; (2) redundancy and diverse routing of transmission operator, balancing authority, and reliability coordinator data exchange capabilities; and (3) testing of alternative or less frequently used data exchange capabilities.[2]

NERC states that the proposed "Reliability Standards TOP-001-4 and IRO-002-5 build upon the improvements made in the prior versions of those standards to further advance reliability."[3] Proposed Reliability Standard TOP-001-4, Requirement R10 has been revised to require the transmission operator to monitor non-BES facilities for

[1] *Transmission Operations Reliability Standards and Interconnection Reliability Operations and Coordination Reliability Standards*, Order No. 817, 153 FERC ¶ 61,178 (2015).

[2] NERC Petition at 1.

[3] *Id.* at 13.

20170417-3001 FERC PDF (Unofficial) 04/17/2017

determining system operating limit exceedances within its transmission operator area, as directed by the Commission in Order No. 817.[4] NERC states that this revision helps to ensure that all facilities that can adversely impact reliability are monitored.[5]

NERC also revised proposed Reliability Standard TOP-001-4 to require that the operator's and balancing authority's data exchange capabilities for the exchange of real-time data needed for real-time monitoring and analysis have redundant and diversely routed data exchange infrastructure within the entity's primary control center and that these capabilities be tested for redundant functionality on a regular basis. Similar revisions are reflected in Reliability Standard IRO-002-5 to clarify the obligations of the reliability coordinator. NERC states that these modifications help support reliable operations by preventing a single point of failure in primary control center data exchange infrastructure from halting the flow of real-time data used by operators to monitor and control the BES.[6] NERC requests that the Commission approve proposed Reliability Standards TOP-001-4 and IRO-002-5 as consistent with its directives in Order No. 817 and find that the proposed Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

NERC's filing was noticed on March 6, 2017, with interventions, comments and protests due on or before April 10, 2017. No interventions, comments or protests were received.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2016), 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.

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[4] Order No. 817, 153 FERC ¶ 61,178 at P 35.

[5] NERC Petition at 3.

[6] *Id.* at 3-4.

20170417-3001 FERC PDF (Unofficial) 04/17/2017

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 (2016).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

Document Content(s)

RD17-4-000.DOCX.....1-3

20170310-3008 FERC PDF (Unofficial) 03/10/2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

OFFICE OF ELECTRIC RELIABILITY

North American Electric Reliability Corporation
Docket No. RD16-10-000

March 10, 2017

North American Electric Reliability Corporation
1325 G Street N.W., Suite 600
Washington, D.C. 20005

Attention: Shamai Elstein
Counsel for North American Electric Reliability Corporation

Reference: Retirement of Regional Reliability Standard TOP-007-WECC-1a

Dear Mr. Elstein:

On March 23, 2016, as supplemented on November 16, 2016, the North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) filed a joint petition to retire regional Reliability Standard TOP-007-WECC-1a - System Operating Limits ("SOL"). The purpose of the proposed retirement is to shift away from the path-centric model and allow entities in the Western Interconnection to align their operating practices with the framework established in the continent-wide TOP/IRO Reliability Standards approved in Order No. 817, which, according to NERC and WECC, achieve the objective of operating within acceptable pre- and post-contingency reliability criteria (i.e., within SOLs and Interconnection Reliability Operating Limits ("IROL").[1]

NERC and WECC state that each of the facilities comprising the 40 major WECC transmission paths would be monitored in accordance with the TOP/IRO Reliability Standards and subject to associated mitigation requirements should there be an expected or actual exceedance of an SOL or IROL on the paths.[2]

NERC's and WECC's joint filing was noticed on February 10, 2017, with interventions, comments and protests due on or before March 3, 2017. Western Area

[1] Supplemental Filing at 3.
[2] *Id*. at 2-3.

20170310-3008 FERC PDF (Unofficial) 03/10/2017

Power Administration and Bonneville Power Administration filed comments in support of the joint petition, but did not intervene. No petitions to intervene or comments opposing the NERC and WECC joint filing were submitted.

NERC's uncontested petition is hereby approved pursuant to the relevant authority delegated to the Director, Office of Electric Reliability under 18 C.F.R. § 375.303 (2016), 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 (2016).

Sincerely,

Michael Bardee, Director
Office of Electric Reliability

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20170530-3023 FERC PDF (Unofficial) 05/30/2017

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, DC 20426

OFFICE OF ENERGY MARKET REGULATION

In Reply Refer To:
North American Electric Reliability Corporation
Docket No. RR17-3-000

May 30, 2017

North American Electric Reliability Corporation
1325 G St NW, Suite 600
Washington, DC 20005

Attention: Lauren A. Perotti
Counsel for the North American Electric Reliability Corporation

Reference: Amended Bylaws and Regional Reliability Standards Development Process

Dear Ms. Perotti:

On March 6, 2017, North American Electric Reliability Corporation submitted proposed amendments to the Texas Reliability Entity, Inc. (Texas RE) bylaws and regional reliability standards development process (RSDP). NERC states that Texas RE proposes to revise its bylaws and RSDP to, among other things, (1) eliminate the Texas RE Reliability Standards Committee and transfer its duties to the Texas RE Member Representatives Committee, (2) add a Texas RE Director Compensation Committee, and (3) revise the activities of the Texas RE Nominating Committee.

Notice of this filing was issued on March 6, 2017, with protests and interventions due on or before March 27, 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, effective as of the date of this order.

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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 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

20170530-3023 FERC PDF (Unofficial) 05/30/2017

Document Content(s)

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UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

NOTICE OF EMERGENCY CLOSING

(February 8, 2017)

Due to logistical issues at the Commission's headquarters, the Commission is closing at 11:00 a.m. today. The emergency closing provisions issued December 18, 2003, in Order No. 645 under Docket No. RM04-3-000 will apply to today's closing.

Kimberly D. Bose,
Secretary.

February 8, 2017
News Media Contact
Mary O'Driscoll | 202-502-8680

No FERC Meeting for February

The Federal Energy Regulatory Commission (FERC) has canceled its February 16, 2017 agenda meeting, Acting Chairman Cheryl LaFleur and Commissioner Colette Honorable announced today. Acting Chairman LaFleur and Commissioner Honorable also have decided, in view of the lack of a quorum, to suspend subsequent monthly agenda meetings until further notice.

Unless otherwise announced, FERC will continue to hold previously scheduled meetings and events sponsored by FERC, including the joint meeting between FERC and the Nuclear Regulatory Commission on February 23, 2017, and the upcoming Hydropower Regulatory Efficiency Act of 2013 workshop on March 30, 2017. FERC also will continue to announce and schedule future meetings, technical conferences and workshops as appropriate.

R-17-22

(30)

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Slow Circuit Breaker Operation Due to Lubrication Issues

Primary Interest Groups
Generator Owners (GOs)
Transmission Owners (TOs)
Distribution Providers (DPs)

Problem Statement
In 2015 and 2016, a total of 19 circuit breaker fail-to-trip operations have been reported through the event analysis process. Twelve of those events were slow-to-trip circuit breakers.

Details
Slow-to-trip circuit breakers are often attributed to mechanism lubrication issues. Adequate lubrication of the circuit breaker mechanism is integral to the circuit breaker operating within specified timings. Proper lubrication of circuit breaker mechanisms is a complex task. Even after long periods of inactivity in harsh environments, the breaker must function without hesitation when suddenly called upon.

Some of the things to consider when determining the required maintenance and the type of lubricant to use are:

- The environment the circuit breaker resides in
- The age of the existing lubricant applied to the mechanism
- The type of components used in the mechanism assembly

Circuit breakers in use today can be new to 60 years old. The lubrication requirements across a fleet of circuit breakers can be a challenge due to continued lubrication with what the manufacturer specified 40 or more years ago, or minimal lubrication since installation. Many of these old lubricants will not last. Some greases will separate, leaving only a dry thickener that can slow the breaker action. Some greases and penetrating oils can change in physical form, leaving what appears to be a varnish-like residue in bearings and other critical friction areas.

Bearing with thickened grease

If digital fault recorders (DFRs) or other timing records show that a breaker had a slow operation, the breaker may subsequently operate within normally expected times. This behavior often indicates that old/failed lubricant adhesion was broken in the first actuation and is likely to happen again if the breaker is not re-lubricated and left undisturbed for a while so the adhesion can re-establish.

Corrective Actions

There are many synthetic lubricants available today that will out-perform and out-last conventional lubricants. Thus, effective cleaning and lubrication with lubricants that stand up to prolonged exposure to harsh conditions are essential in ensuring that breakers will operate properly when needed. Improper lubrication or use of the wrong lubricants will lead to premature equipment failure.

In order for moving parts to perform satisfactorily, they must be kept clean and well lubricated. Part of the function of the lubricant is to exclude contaminants and to flush away wear products. While performing these duties, the lubricant itself will become contaminated and must be renewed periodically to prevent damage to equipment. A lubricant can also deteriorate over a period of time due to the constant exposure to the environment (e.g., temperature changes, changes in humidity, and pollutants), so even if it does not become contaminated, the lubricant must still be removed and replaced occasionally. In addition, special attention needs to be paid to the following:

1. **Avoid mixing products:** Compatibility of lubricants is a concern if they should become mixed. Due to the complex petroleum additives that are now used to create lubricants, it is impossible to predict what effect different products will have on each other or in combination.
2. **New parts**: New bearings are often shipped with a protective substance, such as cosmoline, to protect them from corrosion. It is imperative that this substance be removed to allow for the applied lubrication to adhere properly to the metal surface.

Also note the following:

- Penetrating aerosols and thread release products are solvents, not lubricants.
- Solvents will wash out grease and other lubricants.
- Such Solvents should be used only in emergencies as a short-term measure and only if the unit will be cleaned and re-lubricated within a few days.
- These products will quickly dry up and fail to provide lubrication or prevent friction.

Lesson Learned

- Transmission circuit breakers have become a maintenance challenge because of their extended time in the field without re-lubrication.
- Some circuit breaker mechanism failures have been traced to faulty lubricants and/or questionable lubrication practices.
- Circuit breaker owners need to have a maintenance policy around the types of approved lubricants to be used and a policy on when to remove and replace circuit breaker mechanism lubrication.
  - Use vendor-recommended lubrication maintenance practices.
  - Use periodic breaker timing tests or breaker analyzer checks to discover sticky breaker issues prior to having a breaker failure.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)

Source of Lesson Learned:	NERC Event Analysis
Lesson Learned #:	20170301
Date Published:	March 14, 2017
Category:	Facilities Design, Commission, and Maintenance

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Loss of State Estimator Due to Propagated Database Values with Invalid Data

Primary Interest Groups
Reliability Coordinators (RCs)
Balancing Authorities (BAs)
Transmission Operators (TOPs)
Transmission Owners (TOs) that own and operate State Estimators

Problem Statement
The entity encountered an operational problem, causing the state estimator (SE) to become non-convergent. As a result, the Real Time Contingency Analysis (RTCA) application stopped running. An evaluation indicated that the SE application had encountered invalid data referred to as NaN (not a number, or invalid number, resulting typically from a divide by zero). This created invalid results that were propagated through many of the SE calculations, causing the SE to fail. The NaN values were generated by the application. These values were manually overridden to temporarily correct the issue.

Details
The entity encountered an operational problem, causing the SE to become non-convergent. This caused the RTCA application to stop running.

An evaluation indicated that the SE was failing upon encountering database points containing invalid data, referred to as NaN. The NaN values existed in four points that were SE inputs. These values were propagated by the SE into other points, and ultimately resulted in the SE failure. Additionally, the invalid data was sent via an ICCP link to another entity, Entity A, on the border of its Region and to its Reliability Coordinator (RC) and subsequently to another entity, Entity B, via the (RC). This caused both Entity A's and Entity B's SEs to fail. To correct the SE failures, the NaN values were manually overridden with valid data allowing the SEs to converge, including Entity A and Entity B's SEs. The immediate issue was resolved and the SE and RTCA applications resumed normal operation.

Subsequently, the EMS vendor identified a bug in the EMS software that allowed NaN values to be stored and propagated in database points. The source of the NaNs was identified and the entity is working with the vendor to determine the best solution to prevent recurrence of this issue.

The entity notified the area RC that the SE and RTCA were down and requested that they monitor contingencies until the SE and RTCA could be restored.

The EMS SCADA functionality (control and indication) was not affected by this event and no transmission facilities were impacted.

Corrective Actions

SE and RTCA vendor identified the root cause and implemented a solution to prevent the occurrence and propagation of this invalid data. The vendor provided and administered a fix to address the propagation issue (the entity has implemented this fix successfully). Based on results from the vendor review, evaluation, and identification of the root cause, the vendor implemented two base software fixes to prevent NaNs from being generated and being propagated. These software fixes were issued to the vendor's user base so that corrective action was distributed to all affected users.

Lesson Learned

Although generating and testing invalid numbers is complex and involves processes to replicate, the vendors and entities should invest more efforts to perform such testing and implement software codes specifically intended to prevent the formation and propagation of such values.

Suggested steps to perform in the event of a NaN problem or the potential propagation of other types of invalid SCADA data:

If you are performing updates that could result in sending SE invalid data or if you do not have vendor issued corrective solutions implemented for the NaN issue:

- Halt the incoming ICCP and/or RTU data exchange (to “hold” last known good data) immediately before you reinitialize the SE;
- Check the SE result after re-initialization while still using last known good data and;
- If no “NaN” or other invalid data problems are encountered, restore the ICCP data exchange.

The suggested steps will help protect other parties during SE re-initialization and allow SE results to be validated using last known good data. If the data exchange cannot be halted and a NaN or other invalid data problem is encountered, make sure to inform the other parties immediately so they can take appropriate actions to rectify the problem in their area of control.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20170302
Date Published:	March 14, 2017
Category:	Communications

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Lesson Learned

Dispatched Reduction in Generation Output Causes Frequency Deviation

Primary Interest Groups
Balancing Authorities (BAs)
Generator Operators (GOPs)
Reliability Coordinators (RCs)

Problem Statement
A process conflict during a normal data transfer process resulted in undesirable unit commitment outputs from a Balancing Authority's security-constrained economic dispatch unit commitment software. System operators intervened by identifying and blocking the undesirable dispatches; however, some of the instructions could not be blocked or overridden. This caused the Balancing Authority to experience a reduction in generation output that caused its area control error (ACE) and system frequency to deviate for almost 20 minutes.

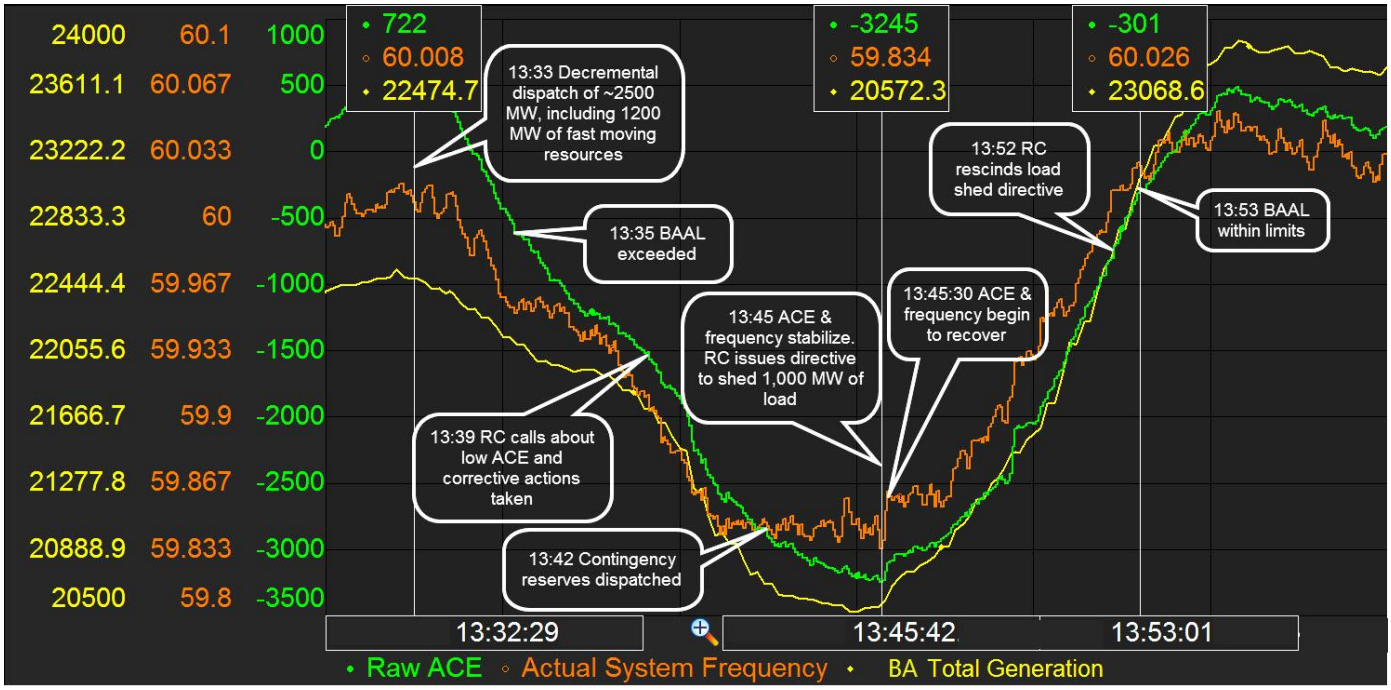
Details
Inadequate data definition resulted in the transfer of incomplete data into the security-constrained economic dispatch unit commitment software, and system operators and support personnel were initially unaware of the incomplete data transfer. The first indication was when the unit commitment software started failing to produce unit commitments for future time periods. The failures continued for an hour while technology personnel were troubleshooting, but there were sufficient unit commitment results from earlier runs, so there were no unit commitment concerns during this time period.

As a result of the long down time, there was an advisory data gap for the period of time when unit commitment results had not been recorded. This caused the unit commitment software to assume many resources were offline, so a large number of startup instructions were issued to compensate. The software dispatches in 5-minute batches from 15-minute advisory runs, so this error caused an initial over generation condition.

The next 15-minute run attempted to balance supply and demand. The software issued a large number of shutdown instructions. System operators and technology support initially tried to determine if the software was self-correcting. After a few minutes, the system operators intervened by identifying and blocking undesirable dispatches; however, some of the start-up and shut-down instructions could not be automatically blocked or overridden as their 5-minute dispatch period had already passed. The system operators phoned and sent messages to scheduling coordinators to ignore dispatches and to verbally verify before following start-up or shut-down instructions.

The software inputs were not consistent with system operator verbal instructions and manual actions. The unit commitment software calculated that there was too much supply to meet demand due to the many startup instructions in addition to the units that had not been shut down as instructed.

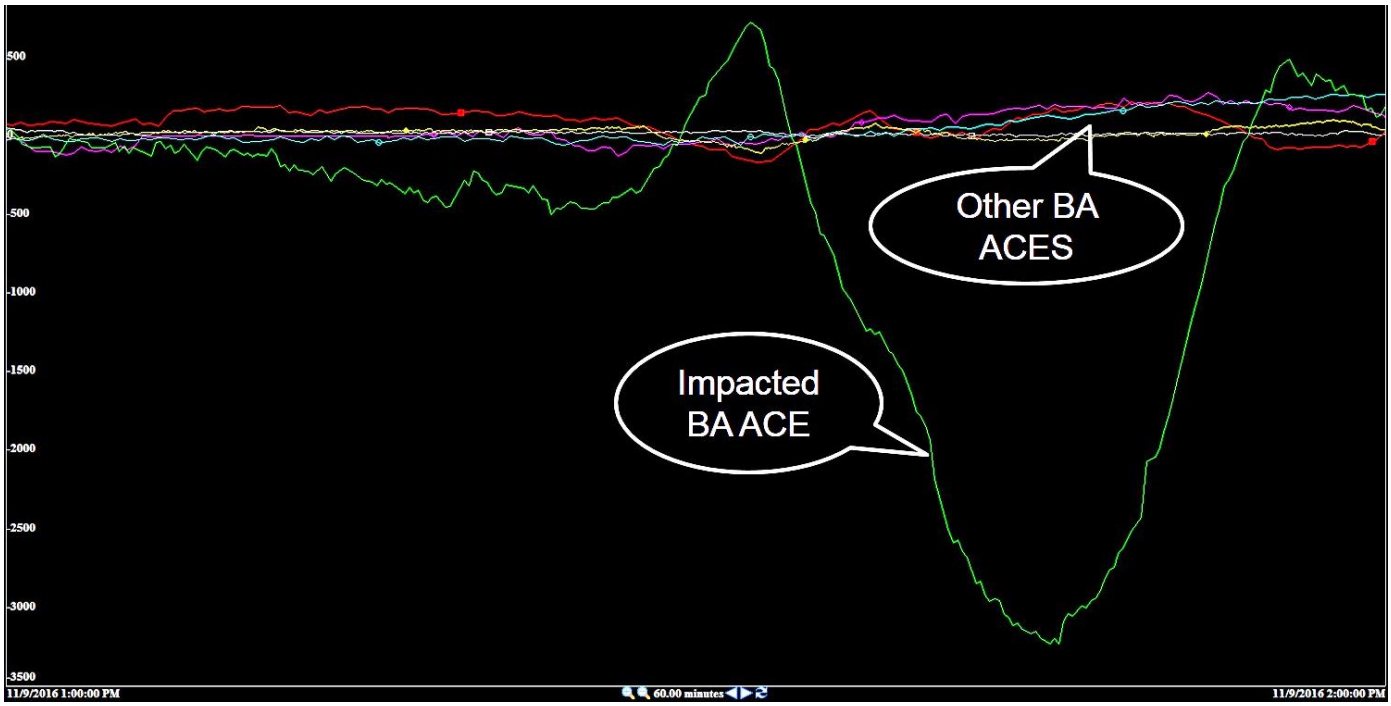
Two-and-a-half hours after the initial event, in order to balance the system under the faulty assumption that too much generation was online, the unit commitment software sent out decremental dispatch instructions of approximately 2500 MW to multiple generator resources via the Automatic Dispatch System (ADS). See time 13:33 on the graphic below.



Due to the volume of the instructions, system operators were unable to block or override the dispatch instructions before they were sent out. System operators verbally instructed scheduling coordinators to not follow the dispatches, but 1200 MW of the dispatch included fast-moving solar generation resources with inverters that can switch off instantly (no ramp time).

Other resources automatically responded to the dispatch signal and reduced their output over an 11-minute period. This reduction in generation output caused the Balancing Authority's ACE and system frequency to deviate. ACE and frequency declined over a 12-minute period and the Balancing Authority ace limit (BAAL) was exceeded for 18-minutes.

The issues were mostly contained within the impacted BA's own area, though they were felt and responded to by their neighbors. This is shown in the following graphic:



Corrective Actions

- The entity identified multiple software and control improvements, including:
  - Resolve data transfer design that led to the data inconsistency into the unit commitment software
  - Improve existing automated controls to block dispatches that exceed certain criteria
  - Improve system operator manual intervention capabilities
- The entity developed additional manual controls for system operators and support personnel until software and automation improvements can be implemented.
- System operators involved in the event developed lessons learned training for system operators and support personnel. The entity identified that it needs to review PER-005-2 tasks for system operators and support personnel to more clearly define overlapping responsibilities. This review will take into consideration the delegation of tasks during abnormal events.

Lesson Learned

- Automated and manual controls for security-constrained economic dispatch software should be reviewed, tested, and operators should be trained in its use periodically under normal and extreme conditions to ensure performance is consistent.
- A system operator and/or a generator operator should be able to intervene to override automated dispatch signals.
- Balancing Authorities should review registered ramp rates of fast-ramping resources and evaluate the amount of ramping the BA can absorb at steady state.

- System operators and support staff should have clear guidance and training on troubleshooting security-constrained economic dispatch software issues that may cause undesirable results. Initial and periodic refresher training should be employed, including reviews of recent cases.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	WECC Event Analysis (via email) or (801) 883-6859
Source of Lesson Learned:	Western Electric Coordinating Council
Lesson Learned #:	20170401
Date Published:	April 12, 2017
Category:	Generation Facilities

This document is designed to convey lessons learned from NERC's various activities. It is not intended to establish new requirements under NERC's Reliability Standards or to modify the requirements in any existing Reliability Standards. Compliance will continue to be determined based on language in the NERC Reliability Standards as they may be amended from time to time. Implementation of this lesson learned is not a substitute for compliance with requirements in NERC's Reliability Standards.

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Lesson Learned

Loss of Monitoring Due to Authentication Software Update

Primary Interest Groups
Reliability Coordinators (RCs)
Balancing Authorities (BAs)
Transmission Operators (TOPs)

Problem Statement
During a scheduled test of updated SCADA/EMS authentication software on the backup control center (BCC), the entity experienced loss of remote monitoring and control that lasted for 51 minutes before full system recovery. During this time, RTU polling ceased, and the ICCP datalink to its neighboring TOP and RC was not operational.

Details
The entity was executing a planned change of the Active Directory (AD) domain used to authenticate users on the SCADA/EMS system. The entity support staff, with assistance of an IT consultant, and prior review with the SCADA/EMS vendor, converted the authentication of users of the SCADA/EMS application from the original system AD domain to the replacement AD domain. The new domain was successfully verified in the entity's test environment, in its operator training simulator, and in its production environment with the primary control center (PCC) as the enabled site. All tests in these environments were successful, including failing over between redundant servers at the PCC.

On the date of the incident, the entity failed over to the backup control center (BCC), to test the new AD authentication on those servers. The authentication mechanism did not work correctly at the BCC site, and operator logins were rejected. SCADA/EMS support staff were unable to force a transfer back to the PCC. The EMS/SCADA vendor was contacted shortly thereafter, and a resolution was identified within 18 minutes. The resolution took another 16 minutes to implement (reboot servers etc.), and the system was fully functional 51 minutes after the loss of monitoring incident began.

During the system outage, the entity activated its contingency plan that requires personnel to be present at a list of critical stations and used manual methods for maintaining visibility of those sites and staffed generation plants.

An investigation was performed that identified the following key contributing factors for this event:

- The authentication failure at the BCC site was caused by incorrect configuration of site localization settings for the SCADA/EMS system at the BCC site.
- The incorrect configuration of localization settings caused a mismatch between the authentication files on disk (which matched between sites) and the authentication records in the system database (which differed between sites), resulting in the inability for operators to login to the system.

Corrective Actions

The entity recommended these steps to address the issues that led to this event:

- Review and correct site localization errors related to authentication.
- In collaboration with the vendor, determine methods to minimize system recovery time when such an incident occurs.

A subsequent test of the corrected configuration, performed seven days later, was successful.

Lesson Learned

- Carefully review all localization settings. Document the purpose of each setting, and develop a process to review these settings prior to and after upgrades or other major configuration changes.
- Consider expanding the SCADA/EMS test environment to provide for site failover testing.
- Utilize recorded voice channels to coordinate all support staff communications during site failover testing.
- Document the specific recovery procedure used in this event for all-servers-down startup.
- Include SCADA/EMS support staff in entity training on loss of supervisory control so that they understand the timings of the process.
- Maintain, within the SCADA/EMS application, at least one "local" user account that is not authenticated via the SCADA AD domain.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	NPCC – Event Analysis
Source of Lesson Learned:	Northeast Power Coordinating Council
Lesson Learned #:	20170501
Date Published:	May 16, 2017
Category:	Communications

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Lesson Learned

Line Frequency Excursion Causes UPS Shutdown and Control Center Evacuation

Primary Interest Groups

Transmission Operators (TOPs)	Transmission Owners (TOs)	Balancing Authorities (BAs)
Reliability Coordinators (RCs)	Distribution Providers (DPs)	Generator Operators (GOPs)
Generator Owners (GOs)		

Problem Statement

A control center was evacuated due to automatic shutdown of transmission switching and generation dispatcher SCADA workstations and system operation center servers. This shutdown was caused by a frequency excursion on the primary source transmission line that was feeding the control center.

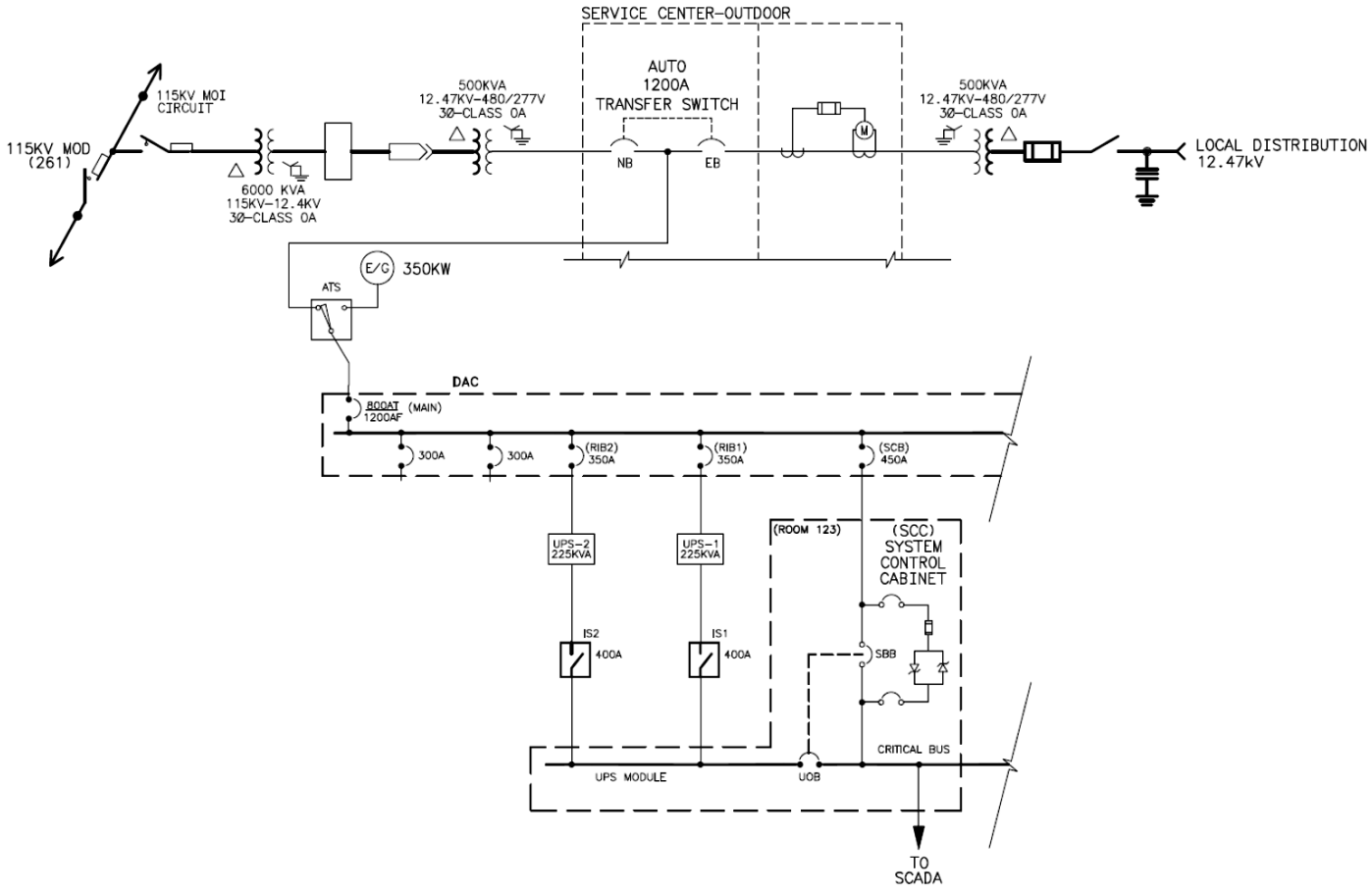
Details

The control center's 115 kV primary source frequency spiked to 65Hz due to events in a neighboring entity's system. The control center's uninterruptible power supplies (UPS-1 and UPS-2) went into hardware shutdown and bypassed due to internal settings that limited acceptable input frequency to a range of 57 to 63 Hz to protect the UPS's front end. Because there was no loss of voltage, the UPS did not change to its battery for its source of power.

With UPS-1 and UPS-2 bypassed, the high frequency from the primary source fed directly to the critical bus. SCADA workstations and other computer equipment energized from the critical bus shutdown when their associated power supplies tripped to protect them. However, business servers and HVAC units remained connected to the critical bus on bypass power. System operations personnel observed the frequency spike just before their workstations shut down. Refer to the diagram on following page for more information.

Because there was no sensed loss of external voltage, emergency diesel generators were not required to auto-start as designed. The control center switched over to its 12.5 kV secondary source following the operation of backup protection on the primary source's transformer. The UPSs remained bypassed and would not pick up critical bus load. Control center personnel evacuated to their alternate control center. The BA maintained monitoring and control functions during the transition.

After some troubleshooting, a logic issue was discovered. The UPSs internal logic would not allow them to pick up load immediately when energized to protect the UPS from feeding a large surge load. The secondary source maintaining the remaining critical bus load (business servers and HVAC) via the UPS bypassed, and this prevented the UPS from returning to normal service. After this internal logic was discovered, all load was powered off. With all load removed, the UPSs were restarted and critical bus load was added slowly, ultimately restoring the control center on secondary source power to the UPSs.



Corrective Actions

- While it would have been possible to turn the SCADA workstations and other computer equipment back on with the UPSs in bypass by using unfiltered secondary source power, this would have put the equipment at risk.
- After control center power has been switched to a known good source (secondary source, batteries, or the diesel generators), turn off all loads fed from the UPS bypass and then bring the UPSs back on. This is the recovery option that was actually used and would have taken less time than evacuating to the alternate control center if the issue had been known previously. Be aware that sometimes UPS logic is set up to require associated batteries be near full charge and an external power source be available before an off-line UPS can be restarted.
- The optimal fix is to prevent power source excursions (frequency hi/low, voltage hi/low) from defeating UPS power in the first place. This may be done by setting up protection and controls to switch input power to another source prior to exceeding one of the UPS front-end protection logic set points. This was the long-term solution chosen by the control center's owner.
- Alternatively, the UPS vendor may provide an option to have the UPS logic changed to switch loads to battery power until an acceptable power source is available instead of simply going into bypass.

Lessons Learned

The primary lesson learned is that despite having four sources of power available (i.e., a primary source transmission line, a secondary source distribution line, emergency diesel generators, and UPS batteries), a control center evacuation was initiated due to a transient on the in-service source due to UPS settings that did not anticipate these conditions.

There is reason to believe this vulnerability may not be unique to the control center involved in this event and could be present in other important applications that use UPS power (such as data centers and generating station control rooms), giving this lesson learned broad applicability.

Entities need to ensure they understand their UPS settings, their UPS' limitations, and how to recover from various potential failure scenarios.

Also see Lessons Learned 20151001 "Loss of EMS Due to RTU LAN and UPS Failure" for another UPS failure scenario.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

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For more Information please contact:

NERC – Lessons Learned (via email)	WECC Event Analysis (via email) or (801) 883-6859
Source of Lesson Learned:	Western Electricity Coordinating Council
Lesson Learned #:	20170502
Date Published:	May 16, 2017
Category:	Communications

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Lesson Learned

Loss of SCADA Operating and Monitoring Ability

Primary Interest Groups
Balancing Authorities (BAs)
Transmission Operators (TOPs)
Transmission Owners (TOs) that own and operate state estimators
Reliability Coordinators (RCs)

Problem Statement
A registered entity's system control center and their commercial operations center experienced a temporary loss of SCADA operating and monitoring capability. As a result, the entity's state estimator and contingency analysis were rendered inoperable for a 50-minute time period. Loss of SCADA connectivity (e.g., monitoring and control) was also experienced with the entity's HVD/LVD substations and the RC. The incident was a result of telecommunication equipment for the SCADA system being inadvertently powered down while non-routine scheduled maintenance was being performed.

Details
Data communications services were provided by a major telecommunications service provider (referred to in this document as the TelCo.) The communication lines passed through a company facility where scheduled elevator maintenance required opening breakers that included the TelCo data switch cabinet(s) in their loads. After the cabinets exhausted their uninterruptible power supply (UPS) batteries, SCADA data transmission to the entity was lost. Upon recognizing the loss of SCADA, the lead system controller notified the RC and requested that adjacent TOs assist in monitoring the electric system. The entity's system controllers took action to rectify the situation. The source of the loss of SCADA capabilities was determined after contacting the data communications service provider (TelCo). The entity decided not to move to their backup control center as they diagnosed the problem and determined that they could correct the issue quicker than activating their backup plan. When power was restored, the SCADA functionality was returned to normal after approximately 50 minutes.

The registered entity conducted a root cause analysis investigation on this incident to identify improvement opportunities and lessons learned. The root cause analysis identified a number of factors that contributed to the Loss of SCADA:

- The electrical panel circuit labeling that described connected equipment (panel schedule) was not up-to-date.
- The power was turned off because the telecommunications and data equipment were not labeled as critical.
- Equipment critical to operations was connected to a UPS circuit but was not backed with a generator.
- System controllers did not know the data service had transitioned to the UPS' battery power until the batteries ran out of power.

- Third party facilities maintenance and the entity did not adequately scope affected equipment and customers prior to performing non-routine work.

Corrective Actions

Corrective actions useful to industry include the following:

- Install alarming on power supplies for critical telecommunications equipment (including external service provider if possible) to provide notification when primary power is not being supplied.
- Identify all critical equipment that needs alarming.
- Coordinate critical equipment work between maintenance and the system control center prior to and during work.
- Include requirements in contract language with service providers to coordinate critical equipment work with the system control center prior to and during work.
- Update facility maintenance procedures to establish semiannual alignment meetings between Facilities, System Control, Merchant Operations, and Information Technology to review the list of critical assets and make updates based on new/changed regulatory requirements.
- Identify and label critical equipment needing UPS with the message "Do not de-energize. Prior to performing work on this equipment, contact XXXX."
- Develop naming conventions and ID types of equipment for each criticality level.
- Update Facilities "Significant Event Job Aid" to include additional contacts when planning work in critical equipment rooms.

Lesson Learned

Preparation and planning of non-routine maintenance work requires an additional level of caution to ensure all potentially impacted stakeholders and critical assets are properly identified. In addition, due to changing regulatory requirements, entities need to establish a process for periodic review and updating of critical asset inventories and backup power needs.

NERC's goal with publishing lessons learned is to provide industry with technical and understandable information that assists them with maintaining the reliability of the bulk power system. NERC requests that you provide input on this lesson learned by taking the short survey provided in the link below.

Click here for: Lesson Learned Comment Form

For more Information please contact:

NERC – Lessons Learned (via email)	RF - Event Analysis (via email) or (216) 503-0636
Source of Lesson Learned:	ReliabilityFirst
Lesson Learned #:	20170503
Date Published:	May 16, 2017
Category:	Communications

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NORTHEAST POWER COORDINATING COUNCIL, INC.
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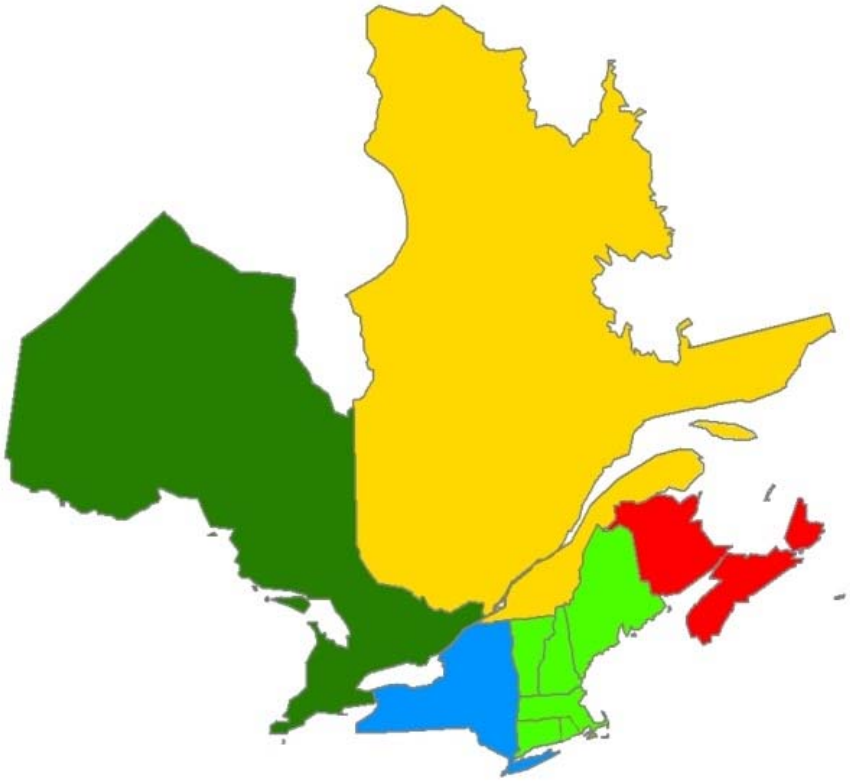
Northeast Power Coordinating Council, Inc. (NPCC)

2018 Business Plan and Budget



Draft 1
Submitted to NERC May 5, 2017

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Introduction

Total NPCC Resources (in whole dollars)	2018 Budget	U.S.	Canada	Mexico
Regional Entity Division FTEs	36.86			
Criteria Services Division FTEs	2.14			
Total FTEs	**39.0**			
Regional Entity Division Expenses	$15,260,967			
Criteria Services Division Expenses	$1,082,983			
Total Expenses	**$16,343,950**			
Regional Entity Division Inc(Dec) in Fixed Assets	**($154,000)**			
Criteria Services Division Inc(Dec) in Fixed Assets	**($16,000)**			
Total Inc(Dec) in Fixed Assets	**($170,000)**			
Regional Entity Division Working Capital Requirement**	**($626,180)**			
Criteria Services Division Working Capital Requirement***	**($47,843)**			
Total Working Capital Requirement	**($674,023)**			
Total Regional Entity Division Funding Requirement	$14,480,787			
Total Criteria Services Division Funding Requirement	$1,019,141			
Total Funding Requirement	**$15,499,927**			
Regional Entity Division Assessments	**$14,341,787**	$XXX,XXX	$XXX,XXX	
Regional Entity Division Assessments Percentage	**100.0%**	XX.X%	XX.X%	
Criteria Services Division Membership Fees	**$1,019,141**	$XXX,XXX	$XXX,XXX	
Total NPCC Assessments & Membership Fees	**$15,360,927**	$XXX,XXX	$XXX,XXX	
NEL	XX	XX	XX	
NEL %	100%	XX.XX%	XX.XX%	

** Refer to Table B-1 on page 66 in Section B.
*** Refer to the Reserve Analysis on page 83 in Section C.

2018 Overview of Total NPCC Resource Requirements

Due to the international nature of NPCC, the total resource requirements including both Regional Entity division and Criteria Services division are identified above. The individual divisional explanations are contained in subsequent sections.

NPCC proposes no change to its total budget and assessments. On a division level, NPCC proposes a Regional Entity total budget decrease of 0.3% and a Criteria Services division total budget increase of 3.8%. The proposed 2018 funding requirements will be satisfied by a Regional Entity division assessment of $14,341,787 and Criteria Services division fees of $1,019,141, for a total of $15,360,927. The total NPCC assessments and fees of $15,360,927 represents no change from 2017. NPCC believes that the Region remains an effective provider of Regional Entity and Criteria Services division functions. NPCC's corporate culture centers on consistent delivery of excellent results at a cost that is considerate of the longstanding tradition in the Northeast of affordable and reliable electricity.

Organizational Overview

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 improving the reliability of the international, interconnected bulk power systems in Northeastern North America 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 a Regional Entity division, as well as Regionally-specific criteria services for Northeastern North America through a criteria services division. NPCC's website is www.npcc.org.

The NPCC Region covers nearly 1.2 million square miles and is populated by more than 56 million people. NPCC U.S. includes the six New England states and the state of New York. NPCC Canada includes the provinces of Ontario, Québec and the Maritime provinces of New Brunswick and Nova Scotia. In total, from a net energy for load perspective, NPCC is approximately 45% U.S. and 55% Canadian. With regard to Canada, approximately 70% of Canadian net energy for load is within the NPCC Region.

Effective January 1, 2016, NPCC executed an Amended and Restated Regional Delegation Agreement with the North American Electric Reliability Corporation (NERC) that delegates to NPCC certain responsibilities and authorities of a cross-border Regional Entity as defined by *Section 215* of the Federal Power Act in the U.S. In addition, NPCC has executed Memoranda of Understanding or Agreements with Canadian provincial regulatory and/or governmental authorities in Ontario, Québec, New Brunswick and Nova Scotia.

It is imperative that NPCC maintain its ability to carry out delegated authorities and responsibilities. NPCC has a flat 2018 targeted staffing level of 39 power industry professionals and support personnel. Details of the 2018 business plans and budget for each program area are included in Section A for the Regional Entity division. The 2018 Regional Entity division schedules are shown in Section B. Section C details the 2018 criteria services division business plan and budget.

Membership and Governance

NPCC monitors approximately 205 registered entities and some 427 functions in the Region for compliance with mandatory Reliability Standards. NPCC currently has approximately 80 members. There are two categories of membership, General and Full. The two categories distinguish between Regional Entity delegated services that are provided in support of the U.S. FERC and Canadian provincial MOUs or Agreements with regulatory and/or governmental authorities, and Criteria Services which FERC references as U.S. non-delegated activities.

General Membership is voluntary and is open to any person or entity, including any entity participating in the Registered Ballot Body of the Electric Reliability Organization (ERO) that has an interest in the reliable operation of the Northeastern North American bulk power system. General Members which are also registered entities within the NPCC Region are subject to compliance with Reliability Standards, consistent with their registration, and also receive additional services from the Regional Entity division of NPCC.

Full Membership is available to Members which are already General Members and participate in electricity markets in the Northeast. Independent system operators (ISOs), Regional transmission organizations (RTOs), Transcos and other organizations or entities that perform the Balancing Authority function operating in Northeastern North America are expected to be Full Members of NPCC. The New York State Reliability Council and any other sub-regional reliability councils which may be formed are also expected to be Full Members. Full Members

are subject to compliance with Regionally-specific more stringent reliability criteria for their generation and transmission facilities on which faults or disturbances can have a significant adverse impact outside of the local area and which are identified utilizing a reliability impact-based methodology, in addition to Reliability Standards, and receive additional services from the Criteria Services division of NPCC, which is not funded through the ERO.

Since January 1, 2012 NPCC is governed by a Board of Directors consisting of seven stakeholder voting sectors consisting of a maximum of two directors per sector, an independent sector consisting of two independent directors, an independent Board Chair with voting rights to preclude board deadlocks, and the President and CEO. Within NPCC, no two sectors can control and no one sector can block action. The voting sectors on the NPCC Board of Directors include:

Sector 1) Transmission Owners
Sector 2) Reliability Coordinators
Sector 3) Transmission Dependent Utilities, Distribution Companies, Load Serving Entities
Sector 4) Generator Owners
Sector 5) Marketers, Brokers and Aggregators
Sector 6) Regulators
Sector 7) Sub-Regional Reliability Councils, Customers, other Regional Entities and Interested Entities
Sector 8) Independent

A Finance and Audit Committee (FAC), a Pension Committee (PC), a Corporate Governance and Nominating Committee (CGNC), and a Management Development and Compensation Committee (MDCC) advise the Board on finance, governance, compensation and human resource matters consistent with their approved charters. The Board endorses a non-employee, Certified Public Accountant for election by the NPCC Members as Treasurer of the corporation. The Treasurer chairs the FAC and works with the Chief Operating Officer who provides oversight of the finances of the corporation. The Treasurer reports to the Board on the corporation's financial position, on FAC activities, on tax code requirements, and on independent annual audit results and accounting practices.

The Regional Standards Committee (RSC), the Compliance Committee (CC), the Reliability Coordinating Committee (RCC), and the Public Information Committee, consistent with their approved scopes, are responsible for various reliability issues. The RSC, CC and RCC also provide technical policy recommendations to the Board. All General and Full Members are eligible for representation on the technical committees.

Industry technical experts from within the membership provide valuable input to the Board through various working groups and task forces as well as the committees. The *Amended and Restated Bylaws* establish NPCC's independence from users, owners and operators of the bulk power system through the enhanced governance structure while providing fair stakeholder representation in the election of the Board of Directors and officers. The members, from each of the seven stakeholder voting sectors, vote to elect directors in their respective sector. The *Amended and Restated Bylaws* establish criteria for board service for both stakeholder and independent directors. Independent Directors are drawn from diverse backgrounds and possess a broad range of industry expertise, perspectives, experiences, skill sets and knowledge to contribute to the effective functioning of a hybrid board structure.

Compliance and enforcement activities are carried out by the NPCC compliance staff and are independent of all users, owners and operators of the international bulk electric system. Compliance activities are governed in the United States by the *Amended and Restated Regional Delegation Agreement* between NERC and NPCC, delegating portions of NERC's authority as the ERO to NPCC. NPCC compliance activities in Canada are governed by individual provincial Memorandum of Understanding (MOU) or Agreements with each province providing the unique parameters for compliance and enforcement activities for each of the provinces. An MOU between the Independent Electricity System Operator in Ontario (IESO), NERC and NPCC establishes roles and responsibilities with regard to that province. NPCC, NERC and the New Brunswick Energy and Utilities Board are parties to a MOU that sets forth reliability activities for New Brunswick. The Régie de l'énergie, NERC and NPCC executed an Agreement regarding the implementation of the Québec reliability standards compliance monitoring and enforcement program. NPCC, NERC and Nova Scotia executed a MOU that sets forth the mutual understanding of the parties in relation to the approval and implementation of NERC Reliability Standards and NPCC Regional reliability criteria for the province of Nova Scotia.

International Foundation

The Regional Entity functions and services differ according to particular regulatory backstop:

a) U.S. Foundation

The Federal Energy Regulatory Commission (FERC) certified NERC as the Electric Reliability Organization (ERO) on July 20, 2006. The ERO is responsible for developing and enforcing reliability standards within the United States. In executing part of its responsibilities, NERC delegates authority to the Regional Entities to perform certain functions through delegation agreements. Ensuring the reliability of the bulk power system in the State of New York and the six New England States was delegated from NERC to NPCC through the Amended and Restated Regional Delegation Agreement.

b) Ontario

On February 5, 2010, NERC, NPCC and the IESO amended and restated their earlier MOU, dated November 29, 2006, setting forth their mutual understanding as regards NERC's and NPCC's status in Ontario with respect to standard and criteria development, compliance enforcement, and other related matters. The IESO, whose statutory responsibilities include making and enforcing reliability standards, and making and enforcing Ontario market rules that govern the IESO-controlled grid and the wholesale electricity market, was established April 1, 1999 as the Independent Electricity Market Operator in Ontario under the *Electricity Act, 1998* (Ontario). The IESO is subject to the regulatory oversight of the Ontario Energy Board (OEB).

Among other things, the MOU recognizes that NERC and NPCC are standards authorities under the *Electricity Act, 1998* (Ontario). Additionally, under the authority of that same legislation, and as memorialized in the MOU, the NERC reliability standards and NPCC reliability criteria have effect in Ontario. However, a 2008 amendment to the Electricity Act, 1998 (Ontario) allows the OEB to review these standards and criteria and issue orders preventing their implementation and remanding them back to NERC and NPCC.

The IESO is subject to compliance monitoring and enforcement by NPCC. The IESO is also subject to compliance monitoring and enforcement of the Ontario market rules by the IESO's Market Assessment and Compliance Division (MACD) that operates at arm's length from the IESO's business units. The MOU notes that where MACD, NERC, and NPCC engage in investigations pursuant to their respective mandates regarding compliance, MACD can request to

take the lead. Moreover, of the three, MACD is the only entity that can assess financial penalties for any Ontario market participant's or the IESO's non-compliance with Ontario market rules, which includes non-compliance with NERC standards and NPCC criteria.

The MOU provides for a peer review process to promote the common compliance and enforcement objectives of NERC/NPCC and MACD. From the perspective of NPCC and NERC, this process, in part, is meant to assure registered entities outside of Ontario that the MACD program is rigorous, thorough and reliable.

The IESO is subject to NPCC assessments of compliance, including audits, as well as NPCC remedial action directives to correct non-compliance. In the event that the IESO disagrees with NPCC's finding of a violation or associated assessment of sanctions in connection with standards and criteria, the IESO has a right to a compliance hearing with NPCC.

c) Québec

The Régie de l'énergie, NERC and NPCC are parties to the May 8, 2009 *Agreement on the Development of Electric Power Transmission Reliability Standards and of Procedures and a Program for the Monitoring of the Application of These Standards for Québec* (the 2009 Agreement). Under the terms of the 2009 Agreement, the Régie de l'énergie , which is charged with ensuring the reliability of the electric transmission in Québec, retained NPCC and NERC as experts to develop reliability standards and monitoring program procedures for the Province.

The Régie de l'énergie, NERC and NPCC are parties to the September 24, 2014, *Agreement on the Implementation of the Québec Reliability Standards Compliance Monitoring and Enforcement Program* (the 2014 Agreement). Through the 2014 Agreement, the Régie de l'énergie retains the services of NPCC to monitor and assess the compliance of registered entities in Québec with the reliability standards adopted by the Régie with respect to electric power transmission in Québec.

On April 1, 2015, the Québec Reliability Standards Compliance Monitoring and Enforcement Program ("QCMEP"), which was developed jointly by the Régie de l'énergie, NPCC and NERC, came into effect. Together, the 2014 Agreement and the QCMEP detail the procedures and program for monitoring and enforcing mandatory electric power transmission reliability standards in Québec.

The Régie de l'énergie is a public body established by the *Act respecting the Régie de l'énergie* (the Act). Pursuant to its authority under the Act, the Régie de l'énergie, through a series of decisions in 2007, designated Hydro-Québec Contrôle des mouvements d'énergie (HQCMÉ), a division of Hydro-Québec TransÉnergie, as the Reliability Coordinator for Québec. In accordance with its mandate and as recognized in the 2009 Agreement, it is this entity that is responsible for the filing with the Régie de l'énergie for approval of reliability standards in Québec. HQCMÉ has filed for the approval of certain reliability standards and the Régie de l'énergie has made certain reliability standards mandatory in Québec and is continuing proceedings to make additional reliability standards mandatory in Québec.

NPCC also conducts reliability assurance activities within Québec, including but not limited to events analysis, Reliability Assessment and Performance Analysis and compliance investigations, consistent with the NPCC *Amended and Restated Bylaws*.

d) New Brunswick

On October 1, 2013, the Electricity Act (NB) and implementing regulations (together, "NB Electricity Act") amended how Reliability Standards are approved, monitored, and enforced in the province of New Brunswick. The NB Electricity Act designates NPCC as a compliance body and NERC as a standards body within the meaning of the NB Electricity Act. The New Brunswick Energy and Utilities Board (NBEUB) is an independent, quasi-judicial board that is responsible for regulating New Brunswick's electricity sector under the NB Electricity Act. The NBEUB has the responsibility to adopt and enforce reliability standards in New Brunswick.

As contemplated in the NB Electricity Act, NPCC and the NBEUB entered into a Service Contract dated August 10, 2016, whereby NPCC provides CMEP and other services for the NBEUB. Additionally, the NBEUB, NPCC, and NERC entered into a Memorandum of Understanding on August 10, 2016, which describes the roles and responsibilities of the three entities and facilitates data sharing. These two documents, along with the NB Electricity Act are the governing documents with respect to conducting CMEP and other reliability related activities in New Brunswick.

With respect to the approval of reliability standards, the NB Electricity Act provides that all of the NERC Reliability Standards that were effective in New Brunswick prior to October 1, 2013 continue to be effective in New Brunswick after October 1, 2013. Additionally, the New Brunswick Power Corporation ("NB Power") is required to file for approval, modification, or retirement of NERC Reliability Standards 60 days after a NERC Reliability Standard is approved, modified, or retired by the Federal Energy Regulatory Commission ("FERC"). The NBEUB rules on the filed Reliability Standard after considering (a) the potential impact on the reliability of the bulk power system, (b) the potential cost and benefits (c) the public interest, and (d) any other factors that the NBUEB considers relevant. The Electricity Act requires the NBEUB to notify NPCC and NERC of an application by NB Power with respect to reliability standards and provide for a 60 day comment period. The NBEUB is required to approve the reliability standards if there are not substantive modifications proposed from the FERC approved NERC Reliability Standard and there were no substantive comments filed. Amendments to the reliability standard to make them compatible with New Brunswick or Canadian law are considered non-substantive. The approval of reliability standards may be subject to a hearing for several reasons, including substantive comments from NPCC or NERC.

With respect to the monitoring and enforcement of the Reliability Standards in New Brunswick, the NB Electricity Act provides for NPCC to identify entities that must register with the NBEUB in the New Brunswick specific registry. Additionally, NPCC may carry out the compliance monitoring and assessment for the NBEUB and assist and advise the enforcement for the NBEUB, including financial penalties. NPCC is also permitted to carry out or exercise any power in the implementing regulations that is specific to the NBEUB, as provided for in the Service Contract. Additionally, NPCC has the powers of an inspector, which permits NPCC to audit and spot check entities within New Brunswick.

e) Nova Scotia

Nova Scotia Power Incorporated (NSPI), NPCC and NERC are parties to a May 11, 2010 Memorandum of Understanding regarding the approval and implementation of mandatory NERC reliability standards and NPCC Regional reliability criteria. Pursuant to the MOU's terms, NERC and NPCC filed standards and criteria with the Nova Scotia Utility and Review Board (NSUARB) for approval on June 30, 2010 and June 29, 2010, respectively. A decision from the NSUARB on both NERC and NPCC filings was rendered on July 20, 2011. Hence, the standards and criteria are mandatory in Nova Scotia and NSPI will be subject to the NERC compliance monitoring and enforcement program, as implemented by NPCC.

NPCC will conduct compliance and enforcement activities with respect to the standards and forward any non-compliance information and recommendations to the NSUARB. The NSUARB maintains the final authority with respect to enforcement in Nova Scotia and based on the recommendations from NPCC, may determine whether a violation has occurred and, if so, what remedial measures or non-monetary penalties should be imposed.

Regional Entity Division Functional Scope

NPCC's Regional Entity division functions in support of the ERO include:

- Active participation in the development of North American Reliability Standards for the bulk electric system, and as needed development of Reliability Standards applicable within the NPCC cross-border Regional Entity
- Monitoring and enforcement of approved Reliability Standards, including the registration of responsible entities, and as needed certification of such entities
- Assessment of the present and future reliability of the bulk power system
- Operational coordination and situation awareness support
- Event analysis and identifying lessons learned to improve reliability
- Effective training and education of reliability personnel
- Promoting the protection of critical electric infrastructure

In recognition of the delegated compliance role of Regional Entities as an important means to enhancing reliability, NPCC has designated a significant percentage of its staff resources to compliance monitoring and enforcement. NPCC has also developed and deployed a robust set of online tools for gathering data, analysis, and tracking of compliance information to support its ability to carry out its responsibilities in a cost effective manner.

NPCC has organized the remaining staff into program areas consistent with EPAct 2005 to address the other functions listed above. These experts in operations, planning and reliability analysis assist registered entities in assessing and improving reliability. It is in support of these areas that NPCC engages the majority of industry experts on its technical committees.

2018 Key Assumptions and 2018 Goals and Key Deliverables

NERC and the eight Regional Entities collaborated in the development of a common operating model with complementary roles and responsibilities, an ERO Enterprise Strategic Plan, and a set of business planning assumptions, goals, metrics and key deliverables for the 2017 through 2019 period. The results from that collaboration, which incorporated risks identified by the Reliability Issues Steering Committee, are included as a set of Shared Business Plan and Budget Assumptions that will be contained in Exhibit A to the NERC 2018 Business Plan and Budget

and may be referenced by the users of this document. NPCC activities that support ERO Enterprise Goals are detailed in each of the following program area sections.

2018 Overview of Regional Entity Division Cost Impacts

The proposed Regional Entity division assessment of $14,341,787 to support the budget is an increase of 0.6% compared to the 2017 assessment of $14,255,061.

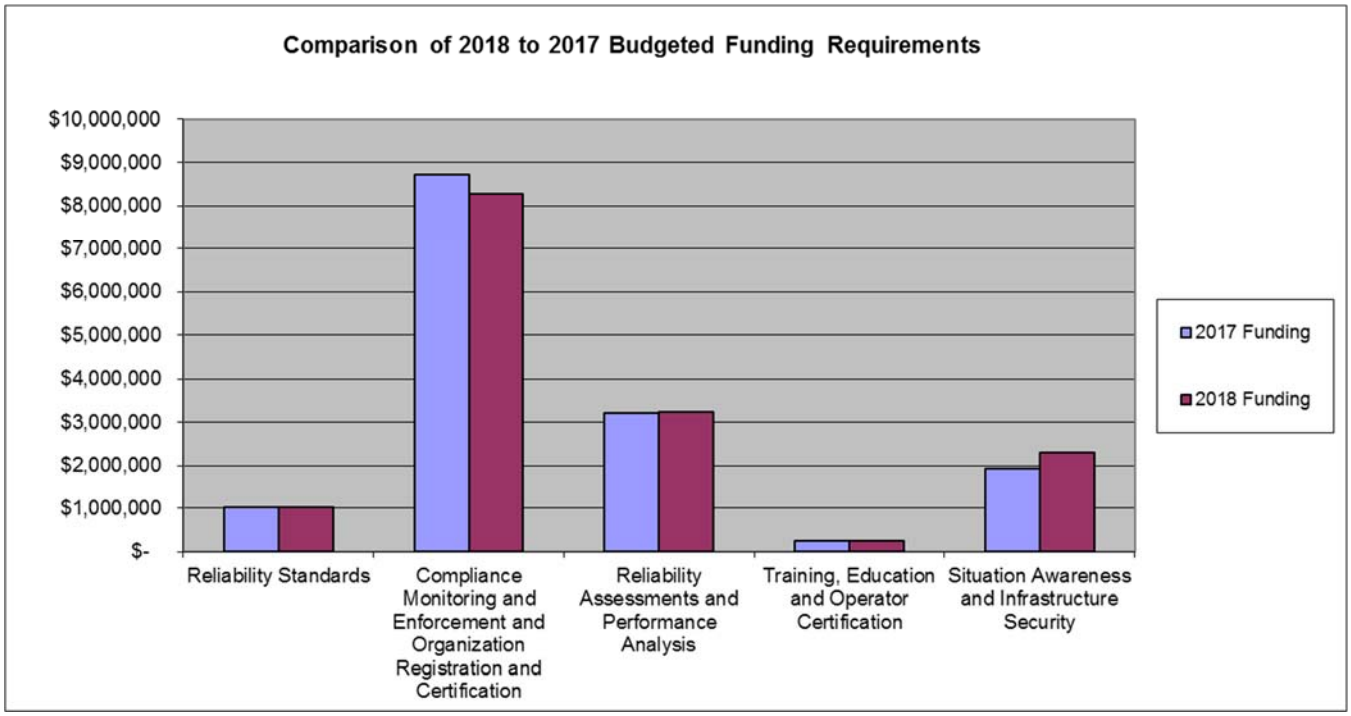
2017 Projections

Current year projections are taken into consideration in development of the budget. Expenses are currently projected to be on budget in all areas or slightly under budget. 2017 Projections reflect expectations based on the first quarter variance report. It is anticipated that projections could change throughout 2017 and would be reflected in each subsequent quarter's variance report.

Summary by Program

Program	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Reliability Standards	$ 1,022,328	$ 1,022,328	$ 1,010,246	$ (12,083)	-1.2%
Compliance Monitoring and Enforcement and Organization Registration and Certification	$ 8,726,049	$ 8,726,049	$ 8,293,748	$ (432,301)	-5.0%
Reliability Assessments and Performance Analysis	$ 3,206,966	$ 3,206,966	$ 3,240,721	$ 33,755	1.1%
Training, Education and Operator Certification	$ 248,658	$ 248,658	$ 249,051	$ 393	0.2%
Situation Awareness and Infrastructure Security	$ 1,943,053	$ 1,943,053	$ 2,313,202	$ 370,148	19.0%
Total	$ 15,147,054	$ 15,147,054	$ 15,106,967	$ (40,087)	-0.3%

This chart does not include allocation of working capital requirements among the Program Areas.



This chart does not include allocation of working capital requirements among the Program Areas.

Personnel Analysis

Total FTE's by Program Area	Budget 2017	Projection 2017	Direct FTEs 2018 Budget	Shared FTEs[1] 2018 Budget	Total FTEs 2018 Budget	Change from 2017 Budget
REGIONAL ENTITY DIVISION						
Operational Programs						
Reliability Standards	1.93	1.93	1.00	0.93	1.93	0.00
Compliance Monitoring and Enforcement and Organization Registration and Certification	17.00	16.00	16.00	0.00	16.00	-1.00
Training, Education, and Operator Certification	0.10	0.10	0.10	0.00	0.10	0.00
Reliability Assessment and Performance Analysis	5.83	5.83	4.90	0.93	5.83	0.00
Situation Awareness and Infrastructure Security	4.00	5.00	5.00	0.00	5.00	1.00
Total FTEs Operational Programs	**28.86**	**28.86**	**27.00**	**1.86**	**28.86**	**0.00**
Administrative Programs						
Technical Committees and Member Forums	0.50	0.50	0.50	0.00	0.50	0.00
General and Administrative	2.50	2.50	2.50	0.00	2.50	0.00
Information Technology	2.00	2.00	2.00	0.00	2.00	0.00
Legal and Regulatory	1.00	1.00	1.00	0.00	1.00	0.00
Human Resources	1.00	1.00	1.00	0.00	1.00	0.00
Accounting and Finance	1.00	1.00	1.00	0.00	1.00	0.00
Total FTEs Administrative Programs	**8.00**	**8.00**	**8.00**	**0.00**	**8.00**	**0.00**
Total FTEs	**36.86**	**36.86**	**35.00**	**1.86**	**36.86**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

2017Budget and Projection and 2018 Budget Comparisons

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget

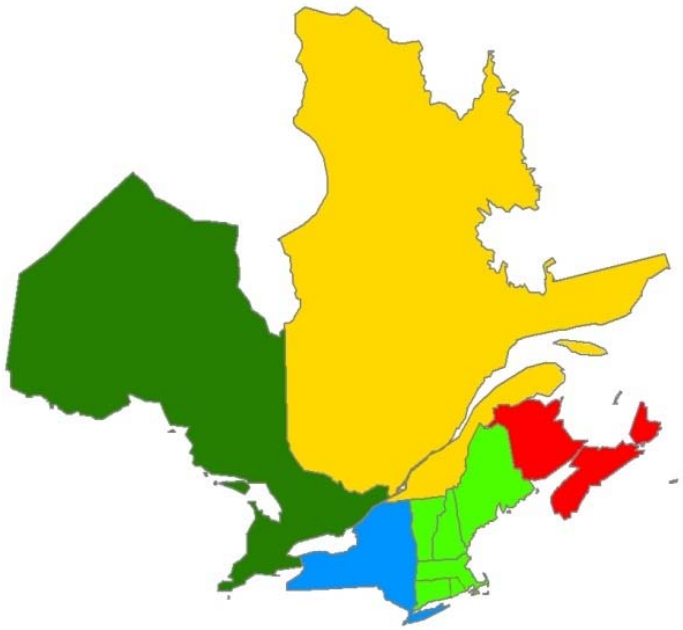
REGIONAL ENTITY DIVISION

	2017 Budget	2017 Projection	Variance[2] 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 14,255,061	$ 14,255,061	$ -	$ 14,341,787	$ 86,726
Penalty Sanctions[1]	-	-	-	75,000	75,000
Total ERO Funding	**$ 14,255,061**	**$ 14,255,061**	**$ -**	**$ 14,416,787**	**$ 161,726**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	64,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 14,319,061**	**$ 14,319,061**	**$ -**	**$ 14,480,787**	**$ 161,726**
Expenses					
Personnel Expenses					
Salaries	$ 6,758,926	$ 6,758,926	$ -	$ 7,107,599	$ 348,673
Payroll Taxes	404,319	404,319	-	411,440	7,121
Benefits	1,415,603	1,415,603	-	1,476,378	60,774
Retirement Costs	847,223	847,223	-	825,353	(21,869)
Total Personnel Expenses	**$ 9,426,071**	**$ 9,426,071**	**$ -**	**$ 9,820,770**	**$ 394,699**
Meeting Expenses					
Meetings	$ 377,100	$ 377,100	$ -	$ 353,050	$ (24,050)
Travel	855,232	855,232	-	834,500	(20,732)
Conference Calls	37,000	37,000	-	37,000	-
Total Meeting Expenses	**$ 1,269,332**	**$ 1,269,332**	**$ -**	**$ 1,224,550**	**$ (44,782)**
Operating Expenses					
Consultants & Contracts	$ 2,009,000	$ 2,009,000	$ -	$ 1,877,640	$ (131,360)
Office Rent	809,700	809,700	-	810,700	1,000
Office Costs	679,100	679,100	-	664,760	(14,340)
Professional Services	1,041,000	1,041,000	-	960,000	(81,000)
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	50,000	50,000	-	50,000	-
Depreciation	250,000	250,000	-	269,000	19,000
Total Operating Expenses	**$ 4,838,800**	**$ 4,838,800**	**$ -**	**$ 4,632,100**	**$ (206,700)**
Total Direct Expenses	**$ 15,534,203**	**$ 15,534,203**	**$ -**	**$ 15,677,420**	**$ 143,217**
Indirect Expenses	**$ (413,149)**	**$ (413,149)**	**$ -**	**$ (416,453)**	**$ (3,304)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 15,121,054**	**$ 15,121,054**	**$ -**	**$ 15,260,967**	**$ 139,913**
Change in Assets	**$ (801,994)**	**$ (801,994)**	**$ -**	**$ (780,180)**	**$ 21,813**
Fixed Assets					
Depreciation	$ (250,000)	$ (250,000)	$ -	$ (269,000)	$ (19,000)
Computer & Software CapEx	276,000	276,000	-	115,000	(161,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	0	0	-	0	-
Inc(Dec) in Fixed Assets (C)	**26,000**	**26,000**	**-**	**(154,000)**	**(180,000)**
TOTAL BUDGET (=B+C)	**$ 15,147,054**	**$ 15,147,054**	**$ -**	**$ 15,106,967**	**$ (40,087)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (827,994)**	**$ (827,994)**	**$ -**	**$ (626,180)**	**$ 201,813**

(1) $75,000 of penalty sanctions collected to date and prior to June 30, 2017.

(2) 2017 Projections reflect expectations based on the 1st quarter statement of activities. It is anticipated that projections could change throughout 2017 and would be reflected in each subsequent quarter's statement of activities.

Section A – Regional Entity Division
2018 Business Plan and Budget



Section A — 2018 Regional Entity Division Business Plan and Budget

Reliability Standards Program

Reliability Standards Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	1.93	1.93	0.00
Direct Expenses	$658,082	$647,633	($10,448)
Indirect Expenses	$372,606	$375,586	$2,980
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($8,359)	($12,974)	($4,614)
Total Funding Requirement	$1,022,328	$1,010,246	($12,083)

Program Scope and Functional Description

The NPCC Reliability Standards Program Area operates in accordance with NPCC's filed and approved Delegation Agreement and NERC Rules of Procedure Section 300. The program supports the ERO standards program area roles and responsibilities, the 2018 ERO Enterprise Strategic Plan and 2018 Shared Business Plan and Budget Assumptions. NPCC's Reliability Standards Program Area provides an efficient and effective mechanism for stakeholders and the ERO to develop reliability standards which are clear, responsive to reliability and security risks, practical to implement, "results based", and are cost effective. The primary objectives of NPCC's Reliability Standards Program Area is to support the development of ERO standards which establishes "results-based" requirements for addressing reliability risks with due consideration given to cost effectiveness. NPCC supports the ERO efforts to develop reliability standards in a timely and efficient manner and which are responsive to FERC Directives and industry risk. ERO and Regional Reliability Standards must ensure the bulk electric system is planned, operated, and maintained in a manner that minimizes risks of cascading failures, avoids damage to major equipment, is responsive to risks, or limits interruptions of bulk power supply.

At the Regional level, the standards program area develops, and maintains NPCC Regional Reliability Standards, ERO Standards Variances for the northeast as required. In addition, the NPCC Reliability Standards Program Area provides oversight to ensure that NPCC's Regional Reliability Criteria contained in the form of Directories, are developed and maintained as necessary to implement, to augment, or to comply with NERC Reliability Standards, but which are not Reliability Standards. Regional Reliability Criteria may also address issues not within the scope of Reliability Standards, such as resource adequacy and conform to requirements in Section 313 of the NERC Rules of Procedure.

The NPCC Reliability Standards Program Area supports and participates in the development, revision, and maintenance of NERC ERO Reliability Standards, initiates new continent-wide reliability standards through the NERC Standards Authorization Request (SAR) process when necessary, and provides a forum for the comprehensive review and improvement of existing and developing reliability standards. NPCC also provides coordination and represents the other seven NERC Regional Entity for the NERC Enhanced Periodic Review process and participates on the Enhanced Periodic Review Standing Team EPRST. The EPRST reviews existing NERC

standards and grades them for quality and content in an effort to prioritize and improve the reliability benefit of the ERO Reliability Standards.

The NPCC Reliability Standards Program Area also facilitates and assists stakeholders with initiating SARs and Requests for Interpretation of ERO standards for those entities within the NPCC footprint. In 2017 NPCC instituted a feedback mechanism from the Compliance, Event Analysis, RAPA and Criteria Services program area which provides a process to identify and improve standards. The standards program area will receive input from these other program areas and take appropriate action to support the revision, retirement, or development of new standards to improve the ERO set of reliability standards and improve reliability of the Bulk Electric System. The NPCC Reliability Standards Program Area conducts its oversight and participation in the ERO standards development process by utilizing the NPCC Regional Standards Committee (RSC) to ensure transparency and facilitate stakeholder input.

The NPCC Reliability Standards Program Area supports the reliability of the bulk electric system by:

- Facilitating active participation of NPCC Regional industry stakeholders in all NERC Reliability Standards activities to promote the development of results-based, cost effective, clear and concise quality standards in a timely and efficient manner.
- Providing selective support for standard development activities as outlined in the NERC 2018-2020 Reliability Standards Development Plan (RSDP)
- Participating in and representing the other Regional Entities on the EPRST which evaluates need to revise existing standards, prioritizes the standards development projects for the future year's RSDP, and allows the Regions to identify opportunities to replace Regional Standards with Variances in the continent wide standards.
- Support ERO outreach during standard development by providing a forum for all NPCC representatives on the NERC drafting teams to raise issues, socialize concepts with stakeholders, and receive feedback on the standards during the development process to enhance efficiency and timeliness of standards development
- Assisting NERC with the evaluation of the standards from a "cost effectiveness" perspective by supporting ongoing pilots and participating in the development of a formal process.
- Promoting awareness by holding Regional workshops to provide outreach and conducting Regional Standards Committee meetings to inform and educate stakeholders on standards being developed, modified or maintained.
- Utilizing input received from the NPCC Regional feedback mechanisms, identify and initiate improvements to NERC standards.
- Actively participate and review the work of the NERC Reliability Issues Steering Committee (RISC) which identifies emerging risks to the BES.
- Coordinating and sharing activities and useful information such as presentations, implementation documents and training materials as necessary with Standards Program Areas from other Regions to enhance efficiencies and promote consistency amongst the Regions.
- Developing and maintaining Regional Standards as necessary to address Regional reliability related issues or risks and ensure those standards set more stringent reliability requirements than the associated NERC Reliability Standard or cover matters not covered by an existing NERC Reliability Standard all in accordance with Section 312 of the NERC Rules of Procedure.

- Pursuing retirement of Regional Standards through promoting the reliability objectives of those Regional Standards into the NERC Continent-wide standards and developing Variances to the NERC standards where possible to capture the reliability objectives of the Regional Standards.
- Maintaining and abiding by the NPCC Regional Standard Processes Manual assuring compliance with all FERC filed documents with respect to standards development.

2018 Key Assumptions

- The number of continent-wide Reliability Standards development projects is expected to remain relatively stable, except as required to address any new FERC directives to create or modify Reliability Standards, or industry submittals of standard authorization requests.
- Continent-wide Reliability Standards projects will consist primarily of conducting periodic reviews on existing Reliability Standards to improve their content and quality, respond to identified risks to reliability (including those that may be identified through the implementation of risk-based Compliance Monitoring and Enforcement), and address FERC directives that may arise. This activity will require the allocation of technical resources from several internal NERC departments (e.g., Reliability Assessment and Performance Analysis (RAPA), Reliability Risk Management, Compliance Analysis and Certification, and Compliance Assurance) and support from across the ERO Enterprise.
- During the periodic review of Reliability Standards, any associated Regional Reliability Standards will be reviewed for potential incorporation as variances or as improvements to the continent-wide requirements. Regional and NERC Reliability Standards development processes may require modification to efficiently accomplish this task. NPCC will work with NERC and other Regional Entities as necessary on projects where there is a Regional Reliability Standard/variance.
- NPCC's Regional Reliability Standards development activity is expected to remain low, driven by requests that the Regional Entity may receive or reliability issues that are identified.
- In coordination with NERC's Standard Drafting Teams and consistent with current approaches, NPCC will support outreach during standard development and participate in the standard development activities as may be required to address reliability and stakeholder issues that may arise.
- Following FERC approval, NPCC will assist with the transition of Reliability Standards to compliance monitoring and enforcement by supporting industry and auditor training or providing information regarding the intent of the Reliability Standard.
- The number of NERC and Regional standards interpretations is expected to remain low. However, implementation guidance requests may increase. The NPCC Reliability Standards program area will assist and facilitate support of these activities.
- Consistent with the NERC Rules of Procedure Sections 312 and 313, as continent wide standards continue to evolve, NPCC Regional Standards and Criteria will need to be continually reviewed to ensure they augment but do not add duplicity to the ERO standards.

2018 Goals and Key Deliverables

The Reliability Standards program goals and objectives for 2018 are grouped into six categories:

1) Participate in the ERO Results-Based Standards Development

- Participate in the annual development and revision of the NERC three year Reliability Standards Development Plan (RSDP)through review, commenting, and other RSC activities
- Participate in the NERC Standards Committee, as a representative of the NERC Regional Entities and NPCC Regional stakeholders to advance strategic initiatives, to measure the effectiveness and quality of standards, participate in standards EPR activities, ensure any outstanding FERC Directives are addressed, and coordinate and prioritize standards development projects
- Support further development of cost effectiveness principles using the "Cost of Risk Reduction Analysis" (CRRA) process and pilots. Continue to provide insights to NERC, based on NPCC experiences, regarding strategy for developing cost effectiveness analysis for standards and identify opportunities to identify cost of risk mitigation for the draft standards
- Participate in the development of ERO Reliability Standards within NERC's three-year standards work plan with the emphasis placed on reducing the amount of new FERC Directives issues by closer coordination with the Commission staff
- Conduct thorough reviews of all NERC standards being developed or revised and coordinate comments for Northeastern North America driving consensus to the extent possible through the Enhance Periodic Review Standing team and processes. Ensure all developing standards receive a review for adequate level of reliability, cost effectiveness and are technologically neutral and focused on achieving a reliability objective
- Assist NERC's review of all industry "Requests for Interpretations" of standards
- NPCC staff, along with NPCC solicited regional drafting team volunteers, will participate in the drafting of ERO standards affecting or potentially affecting reliability in the Eastern Interconnection and provide support for review and development of comments and propose improvements
- NPCC and its members will review and coordinate members' comments on FERC staff informal assessments of the ERO Enterprise as appropriate
- Participate in pre-ballot reviews of ERO standards and coordinate the development of consensus recommendations of the NPCC Members to the NERC Standards Drafting Team (SDT) and provide a list of any unaddressed issues to allow the Members to cast a ballot based on regional concerns to enhance the efficiency of the ERO standards development projects
- Review and identify issues and concerns raised in FERC NOPRs and NOIs for any and all standards related issues as appropriate
- Coordinate and evaluate proposed standards utilizing NPCC's technical task forces, working groups and committees
- Educate and notify stakeholders and regulators about issues related to standards development through various means such as webinars and workshops
- Provide outreach to industry trade groups such as the North American Generator Forum and North American Transmission Forum
- Provide a forum for NPCC review of proposed and posted standards related documents from the NERC Critical Infrastructure Protection Committee (CIPC) and NPCC Task

Force on Infrastructure Security and Technology (TFIST) such as but not limited to whitepapers and technical guidelines

- Participate in the NERC RISC and provide a Regional point of contact for all potential reliability related risks and gaps within the Northeast or as noted by NPCC's stakeholders
- Participate in and provide support to critical standards projects, such as CIP Supply Chain, Facility Ratings (IROL and SOL development), GMD, etc.
- Identify and initiate Regional Variances to the NERC Reliability Standards as soon as possible, allowing incorporation into the continent wide standard
- .
- Provide support and assistance to the ERO, as needed, for conducting Quality Review activities on NERC continent-wide standards
- Continue to develop new and innovative processes to better utilize the limited internal and external resources in the Region to enable sufficient technical review of posted standards and related materials
- Support the ERO and the relationships with FERC and applicable provincial governmental authorities for standards development activities as necessary to accomplish the ERO's strategic goals and objectives
- Participate in the improvement of NERC standards though lessons learned and various ERO and Regional feedback mechanisms using input from Compliance, RAPA, Event Analysis, and stakeholders
- Provide support to the Compliance Guidance Policy activities as required.
- Provide support to ERO staff for FERC related matters in the area of standards development such as pre-filing meetings, preparation of filings, and technical conference participation

2) Regional Standards Development

- NPCC does not plan on developing further Regional Standards but reserves the right to do so if a reliability issue exists that is not appropriate for continent-wide development and also will perform clarifications as needed to existing approved Regional Standards in accordance with all NERC Rules of Procedures and NERC and Regional Standards processes
- Conduct reviews for opportunities to include Regional Standards as Variances into the associated NERC continent wide standards as they individually undergo Enhanced Periodic Reviews
- Conduct periodic reviews of Regional Standards as necessitated by the revision and approval of any associated Continent-wide NERC reliability standards or further reliability related need.
- Conduct the development of any Québec Interconnection Wide variances to NERC continent wide standards using the NPCC Reliability Standards Development Process.

3) Standards Improvement

- Achieve NPCC Northeastern North American reliability goals and objectives by initiating, participating in, and efficiently completing standards related activities and promote these reliability objectives in continent-wide standard development projects
- Leverage internet and web based tools functionality to ensure inter-Regional consistency and quality of Regional Reliability Standards
- Support long-term strategy for standards improvement, help develop and initiate implementation of more efficient processes

- Identify any reliability related need for additional Regional Standards opportunities if continent-wide standards are not an appropriate or possible solution
- Ensure the topics addressed by the Reliability Standards parallel changing industry needs
- Participate in reliability metrics activities to identify potential measures for benchmarking of reliability and standards to determine if an adequate level of reliability is being achieved through the Enhanced Periodic Review Standing Team activities
- Identify opportunities and processes for cost-effectiveness CRRA analysis activities to determine the need to revise a standard during the EPR process
- Identify any emerging interconnection-wide reliability issues which may need standards solutions and forward to the NERC Reliability Issues Steering Committee.
- Identify opportunities to increase reliability through the revision of standards and their associated requirements

4) Business Practices Interface

- Coordinate the review of standards through NPCC RSC, staff, and other members participating in activities of the North American Electric Standards Review Board (NAESB)
- Identify potential market related issues for Regional Standards through NPCC RSC coordination and reviews

Based on the portion of professional/technical staff time and other resources devoted to Reliability Standards development, NPCC estimates that it will expend approximately 7% of its resources on this activity.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Reliability Standards Program

Funding sources and related expenses for the Reliability Standards section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures 2017 Budget & Projection, and 2018 Budget Reliability Standards						
		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 1,022,328	$ 1,022,328	$ -	$ 1,005,230	$ (17,098)
	Penalty Sanctions	-	-	-	5,016	5,016
Total ERO Funding		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**
Expenses						
Personnel Expenses						
	Salaries	$ 370,220	$ 370,220	$ -	$ 377,093	$ 6,873
	Payroll Taxes	21,273	21,273	-	21,390	116
	Benefits	97,411	97,411	-	98,851	1,441
	Retirement Costs	43,020	43,020	-	40,299	(2,721)
Total Personnel Expenses		**$ 531,925**	**$ 531,925**	**$ -**	**$ 537,633**	**$ 5,709**
Meeting Expenses						
	Meetings	$ 13,000	$ 13,000	$ -	$ 7,000	$ (6,000)
	Travel	103,157	103,157	-	93,000	(10,157)
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 116,157**	**$ 116,157**	**$ -**	**$ 100,000**	**$ (16,157)**
Operating Expenses						
	Consultants & Contracts	$ 10,000	$ 10,000	$ -	$ 10,000	$ -
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
	Depreciation	-	-	-	-	-
Total Operating Expenses		**$ 10,000**	**$ 10,000**	**$ -**	**$ 10,000**	**$ -**
	Total Direct Expenses	**$ 658,082**	**$ 658,082**	**$ -**	**$ 647,633**	**$ (10,448)**
Indirect Expenses		**$ 372,606**	**$ 372,606**	**$ -**	**$ 375,586**	**$ 2,980**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,030,688**	**$ 1,030,688**	**$ -**	**$ 1,023,220**	**$ (7,468)**
Change in Assets		**$ (8,359)**	**$ (8,359)**	**$ -**	**$ (12,974)**	**$ (4,614)**
Fixed Assets						
	Depreciation	$ -	-	$ -	-	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(8,359)	(8,359)	-	(12,974)	(4,614)
Inc(Dec) in Fixed Assets (C)		**(8,359)**	**(8,359)**	**-**	**(12,974)**	**(4,614)**
TOTAL BUDGET (=B+C)		**$ 1,022,328**	**$ 1,022,328**	**$ -**	**$ 1,010,246**	**$ (12,083)**

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Compliance Monitoring and Enforcement and Organization Registration and Certification Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	17.00	16.00	-1.00
Direct Expenses	$5,366,656	$5,247,634	($119,022)
Indirect Expenses	$3,282,024	$3,113,668	($168,356)
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	$77,369	($67,554)	($144,922)
Total Funding Requirement	$8,726,049	$8,293,748	($432,301)

Program Scope and Functional Description

The Compliance Monitoring and Enforcement and Organization Registration and Certification Program (CORC) Program scope covers: 1) the identification, registration and certification of those entities responsible for meeting the NERC Reliability Standards and any approved Regional Standards; 2) the implementation of the risk-based NERC Compliance Monitoring and Enforcement Program (CMEP) in the United States, including the compliance monitoring, assessment and enforcement of NERC Reliability Standards and Regional Reliability Standards. and 3) the implementation of compliance monitoring, assessment and enforcement recommendations in accordance with individual executed MOUs or Agreements in the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia.

The NPCC Compliance Committee (CC) is charged with providing objective stakeholder policy input to NPCC's implementation of the CMEP in the U.S. and compliance related activities under the above mentioned MOUs in the NPCC portion of Canada. With regard to NERC Reliability Standards and Regional Reliability Standards, the CC provides an oversight role of the independent NPCC compliance staff's implementation of the CMEP. In this oversight role the CC will review and endorse the processes used by the NPCC compliance staff in the conduct of the CMEP.

The NPCC compliance staff makes the initial and final determination of alleged violations and determines appropriate penalties and sanctions in accordance with the NERC *Sanction Guidelines*. To accomplish this objective, NPCC's compliance staff is further divided into four sub- program areas: Compliance Implementation and Registration; Compliance Entity Risk Assessment, Compliance Monitoring; and Compliance Enforcement.

Compliance Implementation, Registration and Certification

The Compliance Implementation and Registration sub-program is responsible for:

a) Continue to use the risk-based registration model to maintain an accurate registry and correctly identify all entities that are required to meet the NERC and Regional Reliability Standards.
b) Performing the annual review of the recently created enhanced registration database, assuring that all entity data, such as latest entity risk assessment data, BES asset listing, etc.is correct and up to date.
c)
d) Representing NPCC on the NERC –led Review Panel whose role is to make decisions related to resolving - identified registration issues, such as registered entities requests for a materiality assessment, an identification of an applicable subset of NERC Standard requirements, etc;
e) Engaging with those registered entities who are requesting a materiality assessment or an identification of an applicable subset of requirements in advance of these issues being presented to the NERC-led Review Panel;
f) Working within the ERO Enterprise on monitoring the progress of the development and implementation of new Registration and CMEP software reporting systems and tools.
g) Developing and maintaining all NPCC and NERC CMEP Compliance Procedures, Compliance Instructions and all other CMEP related documentation;
h) Developing and maintaining Performance Metrics that are used to measure the quality and effectiveness of CMEP Implementation and its impact on the reliability of the Bulk Electric System;
i) Coordinating the implementation of NPCC Compliance Staff responsibilities as they pertain to the executed MOU with each of the Canadian Provinces in the NPCC Region.
j) Day-to-day implementation of the CMEP;
k) Developing of NPCC's annual CMEP Implementation Plan;
l) Monitoring and assessment of guided self-certification, self-report, exception reporting, periodic data and complaint submittals;
m) Updating and maintaining theCMEP Data Administration Application (CDAA);
n) Implementing required changes and maintenaining the Registration and Compliance portions of the NPCC website.
o)
p) Participating on various NERC and NPCC working groups to influence changes to Compliance processes, and support commonality of registration, monitoring, auditing, and enforcement approaches.

Compliance Monitoring Program

The Compliance Monitoring Program is charged with conducting both on-site and off-site compliance audits, spot checks, and guided self-certifications of NERC Reliability Standards in accordance with the NERC Rules of Procedure and associated NPCC procedures developed under the NPCC Compliance Implementation Program. NPCC's Compliance Monitoring area provides supporting activities by implementation of the risk-based Compliance Monitoring and Enforcement Program (CMEP); and by use of consistent compliance monitoring practices focused on higher reliability risks. NPCC uses risk profiles from the IRAs (inherent risk assessments) as a baseline evaluation of reliability risks of an entity. NPCC also uses IRA summaries to guide its efforts to identifying key focus areas and evolving reliability risks. Internal Control Evaluations (ICE) are performed for registered entities that agree to identify key

focus areas for a CMEP engagement. The result is a list of reliability requirements that merit a continued level of focus.

NPCC also supports the ERO Enterprise learning effort, as well as NERC oversight of program implementation. In collaboration with NERC, NPCC supports outreach programs in new CIP versions and in implementation of CIP-014 with anticipated expansion in the number and type of registered entities that require guidance. Compliance engagements are performed on the basis of risk to the BES and take into account the ERO reliability risk priorities. The Reliability Assessment (RA) group performs an IRA of all registered entities and forwards results to the manager of compliance to develop a schedule. Previous performed IRAs are amended and updated based on identified triggers. The yearly schedule is produced consistent with Risk Assessment of registered entities and the desired frequency of CMEP engagements. The schedule is posted annually on NERC and NPCC public websites.

Flexibility may be used in the CMEP engagement frequency based on the risk assessment and performance based assessment of each entity scheduled for an audit, and changes requiring certification. NPCC compliance monitoring is focused on the most significant risks to the BES. CMEP engagement may be in the form of an audit, spot check or guided self-certification and are led by qualified senior NPCC Staff. Compliance Oversight Plans are developed for registered entities to address the relevant risks. NPCC also conducts outreach, training, and education as necessary to support the implementation of new Reliability Standards.

Findings include the identification of any possible violations. Contents and processing of audit and spot check reports are in accordance with NERC directives for reporting. Specific lessons learned are factored into the program to promote continuous improvement and are presented at workshops. An annual comprehensive guided self-certification program is established based on the NERC and NPCC Risk Elements. Spot checks are based on NPCC's assessment of follow–ups on entities that have previously violated a Reliability Standard, follow-up on entities that have been involved in a significant system event, and other requirements which at the discretion of NPCC could pose a higher risk to reliability if not followed properly.

Resources from the Compliance Audit Program are also used to implement the Certification process for entities intending to register as new TOPs, BAs or RCs, as well as certification reviews of changes made by existing TOPs, BAs and RCs that meet the threshold requiring same. These actions are performed in support of the Compliance Registration Program which encompasses the Certification process. Resources for this activity, which is independent of the audit process, depend on the scope, function, and location of the entity being certified.

Compliance Entity Risk Assessment

The Entity Risk Assessment group conducts activity that informs the risk-based approach for CMEP engagement scoping. They conduct an entity's IRA prior to scoping the compliance engagement to determine which CMEP tool will be used.

Entity risk also includes an assessment of an entity's Internal Controls which is used for further refinement of requirements to be included in the engagement. While separate ICE engagements are voluntary and must be agreed to by the entity, internal controls may also be reviewed as needed during an audit.

Compliance Investigation

A Compliance Investigation (CI) may be initiated at any time by NPCC in response to a system disturbance, complaint, or possible violation of a Reliability Standard identified by any other means. The CI process requires the establishment of an investigation team that coordinates with NERC and FERC as necessary; and also coordinates with the Situation Awareness Program Area.

Compliance Enforcement

In processing identified violations NPCC Compliance Enforcement strives to promote both timeliness and transparency of compliance results utilizing a risk-based compliance enforcement approach, including those efforts associated with meeting the enforcement metrics described below. In addition NPCC promotes the use of self-identification of non-compliance and implementation of discretion, including increased utilization of streamlined tracks such as FFT and discretion as shown below.

Compliance Enforcement responsibilities:

a) Issuing all applicable notices including the Notice of Preliminary Screen; Notice of Compliance Exception; Notice of Possible Violation (NOPV), Notice of Find, Fix and Track (FFT) Treatment; Notice of Alleged Violation (NOAV), and the Notice of Confirmed Violation (NOCV);
b) Conducting comprehensive enforcement investigations based on the facts and circumstances related to all possible violations of Reliability Standards, whether identified in an audit, a self-report, complaint, or other source, and determining whether further action is warranted;
c) Reviewing, approving, submitting to NERC and tracking the progress of all mitigation plans /mitigating activities associated with confirmed violations or noncompliances;
d) Coordinating settlement activities once they have been initiated and submitting settlement agreements to NERC for approval;
d) Identifying and processing applicable moderate violations for the FFT Process;
e) Administer both the compliance exception process and the self-logging process for identified minimal noncompliances;
f) Coordinating the identification of possible NERC Reliability Standards revisions and submit issue for proper implementation. Revisions will be based on experiences observed from compliance monitoring activities, enforcement investigations, and event analysis. Work closely with NPCC Reliability Standards Program Area
g) Following up on verifying that proposed Reliability Standards have been implemented and are effective in improving the standards.
h) Participating in the Hearing Process by representing NPCC before the Hearing Body. Compliance Hearings would be conducted at NPCC under the supervision of a qualified, independent hearing officer contracted by NPCC;
i) Issuing Remedial Action Directives when appropriate; and
j) Implementing the risk-based compliance enforcement model including :
    a. Notifying the registered entity, within 60 days on average, whether a non-compliance will proceed through enforcement, be treated as a compliance exception or additional information is needed ("Triage");
k) Developing and monitoring a set of enforcement metrics that support NERC's Strategic Plan and Oversight Program
l) Processing violations based on the individual executed MOUs or Agreements in the Canadian Provinces of Ontario, Québec, New Brunswick and Nova Scotia.

2018 Key Assumptions and Cost Impacts

2017	Projected 2018
8 On-Site Audits	4 On-Site O&P Audits
12 On-Site CIP Audits	10 On-Site CIP Audits
32 Off-Site Audits	30 Off-Site O&P Audits
11 Off-Site CIP Audits	15 Off-Site CIP Audits
15 Spot Checks	15 Spot Checks
25 Guided self-certifications	25 Guided self-certifications
50 Inherent Risk Assessments	50 Inherent Risk Assessments
10 On-site Internal Control Evaluations	4 On-site O&P Internal Control Evaluations
	5 On-Site CIP Internal Control Evaluations
100 Violations (Estimated)	120 Violations (Estimated)
Settlements Covering 50 Violations	Settlements Covering 50 Violations
2 Hearings (Unbudgeted)	2 Hearings (Unbudgeted)
1 CI (Estimated)	1 CI (Estimated)
2 Entity Certifications	4 Entity Certifications

- Regarding the Compliance Audit Program, Technical Feasibility Exception (TFE) reviews are conducted both on-site at the entity's facility and at the NPCC offices when possible. TFE's continue to be requested as entities replace and install new equipment/devices/components that meet the criteria set forth in Rules of Procedure Appendix 4D. Compliance estimates four on-site reviews will be performed in 2018.
- Decrease in audit costs reflects Risk Assessment activity that is the basis for entity engagement scoping. The Risk Assessment includes an assessment of an entity's Internal Controls which is used for future reduction in engagement scoping and frequency of engagements.
- Potential increases due to the newly identified role related to implementing the QCMEP in Québec and the continuing role of implementing the NB CMEP in New Brunswick.
- The 2018 Business Plan projects no significant increases in Enforcement Processing activities over the 2017 Budget.
- The 2018 Business Plan projects the need for one Compliance Investigation. These Compliance Investigations are manpower intensive for NPCC staff (requiring allocation of more resources and potentially higher than normal costs).

2018 Goals and Key Deliverables

- Conduct 2018 CMEP consistent with a risk-based compliance monitoring and enforcement model, assessing IRA; conducting voluntary ICE; and expanding the use of compliance exceptions and the self-logging program for disposition of minimal violations.
    - Continue to process identified violations as effectively as possible, including the timely identification of a violation and its disposition method (e.g. compliance exceptions; FFT; etc.), and the timely issuance of appropriate notification to the registered entity and NERC;
    - Continue to implement settlement process when applicable and send proper notifications to NERC and FERC and continue to enhance the settlement process

by modifying existing practices and adopting new practices to reduce the duration of settlement negotiations without sacrificing the rigor and quality of the negotiated settlements;
    - Develop and analyze appropriate performance metrics that track settlement process duration and utilize results of analysis to further enhance process.
    - Conduct necessary Hearings related to resolution of outstanding disputes regarding violations and/or sanctions. Send results of hearings to NERC and FERC.
- Identify potential issues related to NERC Reliability Standards as a result of compliance monitoring, enforcement and event analysis activities.
- Implement proposed changes to NERC Reliability Standards utilizing existing mechanisms.
- Verify effectiveness of proposed changes to reliability standards.
- Provide detailed response to NERC Annual FFT/Compliance Exception Survey;
- Implement compliance responsibilities identified in the approved Canadian MOUs;
- Annual report to NERC and Régie on NPCC implementation of QCMEP
- Annual report to NERC and New Brunswick Electric Utility Board (NBEUB) on NPCC implementation of NB CMEP.
- Provide NPCC Regional Entity input, through participation in appropriate NERC compliance committees, on policy and implementation issues related to compliance and enforcement including the development of compliance elements for all new or revised NERC Reliability Standards;
- Provide required information to NERC on a timely basis including reporting of alleged violations and confirmed violations
- Track the progress of report status and approve mitigation plans and mitigating activities;
- Conduct 2018 Compliance Engagement Schedule based on risk to the BES and number of registered entities and promote the ERO Risk-Based Approach initiatives by:
    - Utilizing the Audit Checklist and Auditor's Handbook for all on-site and off-site audits
    - Preparing an Inherent Risk Assessment for all scheduled engagements and Internal Control Assessment for all entities that volunteer for one;
- Assure that NPCC Staff is trained to conduct Entity Risk Assessment and CMEP engagements including CIP Compliance Audit training;
- Assure that NPCC staff is trained to conduct Certification of entities intending to Register as BA, RC or TOP for the first time, or Certification Reviews of changes by existing BAs, RCs or TOPs that meet the criteria requiring a Certification Review;
- Continue to implement compliance reform consistent with a risk-based approach by being an integral participant in committees and workgroups that are involved in the development of polices related to the implementation of a risk-based compliance and enforcement model;
- Continue to expand the utilization of compliance exception and self-logging, as it relates to the processing of minimal noncompliances;
- Continue collaboration with ERO Enterprise on consistent compliance monitoring and enforcement practices specifically those with higher reliability risks.
- NPCC will collaborate with NERC to promote better coordination, planning, delivery and management of training efforts across the enterprise through a unified learning

management system (LMS), without adversely impacting region-specific training requirements;
- Continue to implement physical security outreach and cyber security outreach by visiting registered entity sites to perform an assessment of their physical security, evaluate their cyber security and supply recommendations for improvements;
- Provide outreach to the registered entities, related to the latest status of the development and implementation of the ERO Enterprise Registration and CMEP software reporting systems and tools;
- Work with ERO Enterprise, through NPCC participation on the NERC-led Review Panel, to propose a list of possible ROP enhancements related to the NERC-led Review Panel processes and procedures.
- Conduct 2018Compliance Workshops and interim information sessions for registered entities as necessary as a part of the Training and Education program area.
- Continue to promote practices to enhance the benefits of the self-reporting of violations by the registered entity. This could include the emphasis on the benefits of a registered entity improving its internal processes used for identifying and submitting self-reports, improvement in the way Regional Entities process self-reports, and the streamlining and standardizing of the amount and type of data needed to evaluate a self-report.

Based on the portion of professional/technical staff time and other resources devoted to Compliance monitoring and enforcement and organizational registration and certification, NPCC estimates that it will expend 54% of its resources on this activity.

Resource Requirements

Personnel

- There is a decrease of one FTE in 2018 from the 2017 budget. This is the result of reprioritization during 2017.

Consultants and contracts

- In 2018, contractor costs will continue to decrease due to the implementation of the risk-based approach. With a risk and performance based assessment of each registered entity, compliance engagements will transition to a periodicity more reflective of the risk profile of the entity such that some will result in audits which are more in-depth while others may have a reduced scope which will result in spot checks or guided self-certifications.

Compliance Monitoring and Enforcement and Organization Registration and Certification Program

Funding sources and related expenses for the compliance enforcement and organization registration and certification section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
Compliance Monitoring and Enforcement and Organization Registration and Certification

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 8,084,046	$ 8,084,046	$ -	$ 7,610,165	$ (473,881)
Penalty Sanctions	-	-	-	41,580	41,580
Total ERO Funding	**$ 8,084,046**	**$ 8,084,046**	**$ -**	**$ 7,651,745**	**$ (432,301)**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 8,084,046**	**$ 8,084,046**	**$ -**	**$ 7,651,745**	**$ (432,301)**
Expenses					
Personnel Expenses					
Salaries	$ 2,749,908	$ 2,667,408	$ (82,500)	$ 2,716,635	$ (33,273)
Payroll Taxes	179,504	172,004	(7,500)	171,841	(7,663)
Benefits	519,457	506,707	(12,750)	524,801	5,344
Retirement Costs	290,486	279,236	(11,250)	282,356	(8,130)
Total Personnel Expenses	**$ 3,739,356**	**$ 3,625,356**	**$ (114,000)**	**$ 3,695,634**	**$ (43,722)**
Meeting Expenses					
Meetings	$ 23,800	$ 23,800	$ -	$ 9,000	$ (14,800)
Travel	329,500	322,750	(6,750)	289,000	(40,500)
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 353,300**	**$ 346,550**	**$ (6,750)**	**$ 298,000**	**$ (55,300)**
Operating Expenses					
Consultants & Contracts	$ 1,274,000	$ 1,274,000	$ -	$ 1,254,000	$ (20,000)
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 1,274,000**	**$ 1,274,000**	**$ -**	**$ 1,254,000**	**$ (20,000)**
Total Direct Expenses	**$ 5,366,656**	**$ 5,245,906**	**$ (120,750)**	**$ 5,247,634**	**$ (119,022)**
Indirect Expenses	**$ 3,282,024**	**$ 3,282,024**	**$ -**	**$ 3,113,668**	**$ (168,356)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 8,648,680**	**$ 8,527,930**	**$ (120,750)**	**$ 8,361,302**	**$ (287,379)**
Change in Assets	**$ (564,634)**	**$ (443,884)**	**$ 120,750**	**$ (709,557)**	**$ (144,922)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	151,000	151,000	-	40,000	(111,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(73,631)	(73,631)	-	(107,554)	(33,922)
Inc(Dec) in Fixed Assets (C)	**77,369**	**77,369**	**-**	**(67,554)**	**(144,922)**
TOTAL BUDGET (=B+C)	**$ 8,726,049**	**$ 8,605,299**	**$ (120,750)**	**$ 8,293,748**	**$ (432,301)**
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (642,003)**	**$ (521,253)**	**$ 120,750**	**$ (642,003)**	**$ 0**

Reliability Assessment and Performance Analysis Program

Reliability Assessment and Performance Analysis Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	5.83	5.83	0.00
Direct Expenses	$2,106,675	$2,145,368	$38,692
Indirect Expenses	$1,125,541	$1,134,543	$9,002
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($25,251)	($39,190)	($13,939)
Total Funding Requirement	$3,206,966	$3,240,721	$33,755

Program Scope and Functional Description

NPCC, through its top technical committee, the Reliability Coordinating Committee (RCC), integrates the deliverables of its Task Force's and Working Group's Reliability Assessment and Performance Analysis related activities. Consistent with the applicable NERC Reliability Standards, these efforts include:

- Reviewing the adequacy of the NPCC systems to supply load considering forecast demand, installed and planned supply and demand resources and required reserves; and,
- Assessing the impact of planned transmission and resource additions or modifications on NPCC system reliability.

Seasonal assessments of the overall NPCC resource adequacy assessments are performed and possible actions to mitigate any potential problems are identified. NPCC reviews operations and disturbances both internal and external to the Region in order to identify any lessons to be learned and recommends any necessary follow-up actions.

If appropriate, enhancements to Regional Standards or NPCC's more stringent, Regionally-specific reliability requirements are also recommended. NPCC promotes and conducts both inter-Area and inter-Regional studies to enhance reliability and operational effectiveness, and provides a forum for the discussion and coordination of operating issues within the NPCC Region and with other Regions.

2018 Key Focus Areas

In collaboration with NERC, Key Focus area activities for 2018 include:

- ✓ Integration of RAPA information systems for assessments and associated data requirements, including expanded and enhanced enterprise-wide data collection and analysis systems and capabilities for performance analyses, with a focus on independent and technically sound reliability assessments supporting delivery of high quality reports (e.g., Long-Term Reliability Assessment, short-term special assessments, probabilistic scenario assessments, and the State of Reliability Report).
- ✓ Development of assessment and performance analysis techniques as well as resource capabilities and tools, including probabilistic and scenario evaluations, which address the impacts of new technologies, changing resource or demand resource composition, and environmental related regulations or legislation; support for ERO activities to identify key

reliability risks and appropriate risk control projects designed to enhance reliability or mitigate risks.

- Developing and tracking of metrics associated with Essential Reliability Services;
- Developing of appropriately tailored analysis and overall assessment, including guidance for registered entities, of high impact, low frequency BES risks, including physical security and geomagnetic disturbance (GMD) vulnerability;
- Providing technical resources to support up to four short-term special reliability assessments (6-18 month horizon replacing the current summer and winter assessments), which focus on specific reliability issue risk areas and geographic areas with specific reliability concerns, while also allowing for regional assessments;
- Supporting the common approach developed for NERC reliability assessments to ensure consistent treatment of resource and reliability evaluations;
- Advancing analytical capabilities for identifying and determining reliability risks and conducting various reliability assessments by:
  - Integrating the analysis and measures of the identified essential reliability services into the NERC 2018 Long-Term Reliability Assessment;
  - Requiring advanced powerflow and stability analysis tools and objective expert input for transmission/deliverability assessments and studies;
  - Maturing and developing interconnection-wide analysis groups to support the assessment of interconnection-wide risks, such as frequency response;
  - Providing technical resources and reliability leadership for the advancement of probabilistic analyses supporting the Long-Term Reliability Assessment;
  - Enhancing the capability for post event analysis, including ensuring the timely and accurate compilation and creation of steady state and dynamic simulation model cases for use in the investigation and analysis of major power system disturbance events.

✓ NPCC supports, through the Eastern Interconnection base case designee agreement, the development of long-term sustainable interconnection-wide powerflow and dynamics model cases under Reliability Standards MOD-032 and MOD-033 that exhibit the accuracy and fidelity reflecting actual BES reliability performance and dynamic conditions.

✓ Provision of technical resources to support the effective and continuous improvement of the models that incorporate recognition of reliability behavior of loads and generation associated with the changing resource mix.

Eastern Interconnection Reliability Assessment Group

The primary function of the Eastern Interconnection Reliability Assessment Group (ERAG) is to support reliability of the bulk-power system in the Eastern Interconnection through periodic reviews of generation and transmission expansion. These assessments are conducted by the ERAG Steering Committees. The assessment-related activities indicated for the ERAG Management and Steering Committees below, are done in support of ERO Goal 3: "*Identification and Mitigation of Significant Risks to Reliability*."

In addition, ERAG has the responsibility to facilitate the development of the annual set of seasonal and future steady state and dynamic simulation base cases for use by the Regional Entities and other industry groups in the Eastern Interconnection. This is done through the ERAG Multi-Regional Modeling Working Group (MMWG). The base case compilation and development-related activities indicated for the ERAG Management and MMWG below are done in support of ERO Goal 3 related contributing activity to: "Develop guidelines and industry practices to maintain accurate system models that include the resources (synchronous and inverter based), load, and controllable devises providing essential reliability services." NPCC participates in the ERAG activities as one of the six Eastern Interconnection Regional Entities.

NPCC supports maintenance of the BESnet application and the processing of the Regional BES Exception Requests (ERs), including technical validation of the definition and exception requests periodic reviews of network changes affecting BES determinations, as well as requests for registration and certification reviews. Processing of BES Exception requests and recertification of previously approved BES Exception Requests are not expected to significantly impact resources requirements in this program area for 2018.

NPCC RAPA staff participates with the ERAG Management Committee, ERAG Steering Committee and ERAG Working Group and acts as the liaison between the ERAG MMWG and the NPCC SS-37 Working Group; activities include:

ERAG Management Committee Activities 2018 Goals and Deliverables

- ✓ Oversee the steady state and dynamic simulation base case data compilation and development;
- ✓ Oversee ERAG Multi-Regional Modeling Working Group (MMWG) changes to the dynamics base cases;
- ✓ Oversee MMWG effort to make necessary changes to the modeling of governor-turbine control systems to achieve frequency response that more closely reflects actual response during system frequency deviation events;
- ✓ Oversee the ERAG assessments of anticipated inter-Regional, inter-Balancing Authority transfer limit conditions and sensitivities. ERAG is considering different assessment approaches to enhance the way assessments are conducted to provide more industry value from the assessment results. Coordinate the effort with NERC Assessment Program staff;
- ✓ Develop ERAG Strategic Direction (i.e. anticipated new developments in MMWG process and system assessments); Resolve any issues with application of the ERAG MMWG non-disclosure agreement process so that base cases and assessments have sufficient protections in place for use and transmittal of confidential data and information; and,
- ✓ Develop and approve the ERAG activity budgets.

Multi-Regional Modeling Working Group 2018 Goals and Deliverables

- ✓ Facilitate the completion of the steady state and dynamic simulation base case data compilation and development for the 2018 series of cases. This will include 12 steady state base cases and 8 dynamic simulation base cases;
- ✓ Check and confirm that the dynamic model data passes all applicable checks and acceptance criteria. Include 60 second steady state simulation of each case to detect numerical errors;
- ✓ Apply changes to the MMWG dynamics case so they are available for interconnection dynamics studies;
- ✓ Incorporate dispatch information into the future and seasonal ERAG MMWG base cases so that the dispatches are more closely aligned with economic dispatch practices;
- ✓ Apply the web-based System Dynamics Data Base program during the development of the 2018series of dynamics base cases;
- ✓ Continue to improve the representations of the governor-turbine plant control models at most generators. Recommend the necessary changes in the models for specific generators;
- ✓ Apply MMWG base case non-disclosure agreement process so that MMWG cases continue to have sufficient protections in place for use and transmittal of confidential data and information; and,
- ✓ Verify that procedures in the MMWG manual are followed.

ERAG System Assessments 2018 Goals and Deliverables

- ✓ Conduct the 2018 ERAG Assessments and prepare the ERAG Assessment Reports, including, the assessments of anticipated inter-Regional, inter-Balancing Authority transfer limit conditions and sensitivities;
- ✓ Consider different assessment approaches to enhance the way assessments are conducted; and,
- ✓ Coordinate Assessment efforts with the NERC Reliability Assessment and System Analysis (RASA) Program staff to incorporate any risk-based or other approaches to supplement NERC Assessments.

2018 NERC Activities

NPCC will provide the Regional perspective with judicious NPCC RAPA staff participation on selective NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups which include:

- ✓ Essential Reliability Services Working Group (ERSWG);
- ✓ Load Modeling Task Force (LMTF);
- ✓ Protection System Mis-operations Task Force (PSMTF);
- ✓ Demand Response Availability Data System Working Group (DADSWG);
- ✓ Generating Availability Data System Working Group (GADSWG);
- ✓ Transmission Availability Data System Working Group (TADSWG);
- ✓ Power Plant Model Verification Task Force (PPMVTF);
- ✓ Reliability Assessment Subcommittee (RAS);
- ✓ Probabilistic Assessment Working Group (PAWG);
- ✓ System Analysis and Modeling Subcommittee (SAMS);
- ✓ Performance Analysis Subcommittee (PAS);
- ✓ Misoperation Information Data Analysis System (MIDAS); and,
- ✓ Incorporating any probabilistic reliability metrics required for the 2018 NERC Long-Term Reliability Assessment through the NPCC 2018 Long Range Adequacy Overview.

ERO – Executive Management Group (EMG) 2018 Activities

Provide analytic support for the ERO-EMG:

- ✓ Bulk Electric System Exception Process Working Group (BEPWG);
- ✓ ERO-RAPA Group; and,
- ✓ Other activities as directed by the ERO-Executive Management Group.

2018 Goals and Key Deliverables

Task Force on Coordination of Planning

The primary mission of the NPCC Task Force on Coordination of Planning (TFCP) is to promote reliability through the coordination of NPCC Area and NERC planning processes and activities. In addition, the TFCP provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee as requested, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on Coordination of Planning activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability.*" A related contributing activity to ERO Goal No. 3 is to "Develop advanced and probabilistic methods to evaluate resource adequacy." Related contributing activities associated with ERO Goal No. 4

include "Enhance reliability assessments to reflect changing resource mix behavior, including distributed energy resources and essential reliability services, using probabilistic approaches that consider the variable and energy-limited nature of the evolving resource mix," and "Assess risks associated with cross sector dependencies and single points of disruptions."

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Coordinate NPCC responses to NERC Essential Reliability Services Working Group recommendations with the Task Force on Coordination of Operation and the Task Force on System Studies to ensure that developments in the NERC Planning Committee and its Subcommittees are addressed;
- Coordinate the development of additional Criteria as necessary, and track any new and developing standards through the Regional Standards Committee;
- Monitor the development of Bulk Power System (BPS) Regional Standard;
- Oversee NPCC Directory No. 1 Implementation Plan (Dated: September 30, 2015);
- Through the CP-8 Working Group:
    - conduct the annual NPCC Long Range Adequacy Overview and associated NERC RAS requested scenarios and/or special probabilistic studies/assessments;
    - Conduct a review of NPCC Interconnection Assistance Reliability Benefits;
- Evaluate and approve NPCC Area Transmission Reviews;
- Evaluate and approve NPCC Area reviews of Resource Adequacy;
- Coordinate, monitor, review, and make recommendations on the retirement of existing in-service Special Protection Systems (SPS)Remedial Action Schemes (RAS); and the implementation of proposed new or modified SPS/RAS;
- Monitor industry practices and make recommendations to NPCC on transmission adequacy standards related to intermittent generation such as wind or solar-photovoltaic and demand-side resources; and,
- Lead the NPCC Task Forces in the completion of the review and revision the *A10 Criteria–NPCC Classification of Bulk Power System Elements*.

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Support related reliability activities, including consideration of any requests for sub-regional assessments or NPCC's identification of the necessity for such assessments consistent with NERC Rules of Procedure section 805, associated with implementation of the State related resource/environmental initiatives;
- Monitor the actions of applicable NERC Subcommittees in the areas of resource adequacy, system protection and system control;
- Through the CP-8 working Group, review the load shape assumption used in NPCCC Multi-Area Probabilistic Reliability Assessments;
- Review and comment on the development of NERC Standards through the RSC;
- Monitor the developments in fuel supply, demand resources, energy efficiency, and conservation methods including all intermittent renewable resources, including embedded distributed resources;
- Support the NPCC Regional Standards Committee (RSC) as required; and,
- Keep informed on studies and developments with neighboring systems which might impact NPCC.

TFCP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- Monitor the process for the annual review and updating of the NPCC Electric System Regional Map and the NPCC Load, Capacity, Energy, Fuel and Transmission Report (LCEF&T);
- Keep informed of the NERC Planning Committee and other subcommittee activities to determine their impact on the NPCC and any potential adjustments to NPCC Criteria;
- Coordinate with NERC regarding the development of standards for dynamic system controls; and,
- Review Events Analysis Lessons Learned using the Events Analysis discussion/review template.

Task Force on System Studies

The primary mission of the NPCC Task Force on System Studies (TFSS) is to provide active overall coordination of system studies of the reliability of the interconnected bulk power systems and for the review of certain NPCC documents. In addition, the TFSS provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on System Studies activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability.*" A related contributing activity to ERO Goal No. 3 is to "Develop guidelines and industry practices to maintain accurate system models that include the resources (synchronous and inverter based), load, and controllable devices providing essential reliability services." A related contributing activity to ERO Goal No. 4 is to "Develop sufficiency/adequacy guidelines for essential reliability services, including considerations of reliability attributes under a more diverse resource mix and changing load behaviors, such as ramping, reserve services and voltage support."

TFSS Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review and recommend approval of Area Transmission Reviews, in accordance with the "Guidelines and Procedures for NPCC Area Transmission Reviews" (Appendix B of Directory No. 1), based on material presented by the Areas. These reviews assess the impact of planned transmission and resource additions or modifications on system reliability, and determine the Area's conformance with the Basic Criteria. Through the Area Transmission Reviews, re-evaluate the performance and classification of existing SPSs and Dynamic Control Systems;
- ✓ Review and classify new and modified Special Protection Systems and/or Remedial Action Schemes, in accordance with the Appendix B, Procedure for the Review of a Special Protection Systems, of NPCC Directory No. 7, "*Special Protection Systems*";
- ✓ Review and Implement the NPCC A-10 Criteria:
    - Coordinate with TFCP to complete the review and revision of the A-10 document;
    - Review and recommend approval of changes to the NPCC list of bulk power system elements, in accordance with the "*Classification of Bulk Power System Elements*" (Document A-10); and,
    - Update the NPCC BPS List;

- ✓ Review and process Multiple Circuit Tower exclusions in accordance with NPCC Directory No. 1, Appendix E;
- ✓ Update the Multiple Circuit Tower Exclusion List;
- ✓ Perform annual review and update of the Major Project List;
- ✓ Through the SS-37 Working Group:
  - Annually develop a library of power flow base cases and associated dynamic cases. The NPCC cases will also be used to support the development of the library of power flow and dynamic cases for the Eastern Interconnection; in addition: update SS-37 Procedure Manual and other SS-37 documents including the Master Tie Line Data and Interchange Schedule;
  - Provide mid-term updates to the ten-year-out cases in the NPCC Library; and,
  - Perform event replication by benchmarking simulations against actual system performance.
- ✓ Perform the NPCC Under Frequency Load Shedding Assessment;
- ✓ Through the SS-38 Working Group:
  - consider the development of a uniform approach, as requested by TFSP, for identifying BES Elements that meet one or more of the Criteria in R1 of PRC-026-1;
  - Continue to instigate the use of dynamic load models for transient stability studies; and,
  - Work with the NERC Load Modeling Task Force to ensure consistency in load modeling and to share best practices.

TFSS Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Participate in the development and submission of NPCC comments/inputs into the development of regional and/or continent-wide reliability standards that address the NERC Reliability Standards.
- ✓ Provide support and technical input, for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee (RISC);
- ✓ Review existing Regional Criteria and procedures for validation of data used in power flow and dynamic simulations and if the existing criteria or procedures are found to be deficient, propose changes to provide for adequate data validation.
- ✓ Through the SS-38 Working Group:
  - Coordinate management of governor models used in NPCC studies;
  - support the performance of event replication by benchmarking against actual system performance;
  - review and develop comment on draft NERC standards; and,
  - Work with software vendors and NERC systems Analysis and Modeling subcommittee (SAMS) to enhance the capability for dynamic simulations.

Task Force on System Protection

The purpose of the NPCC Task Force on System Protection (TFSP) is to promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America through the establishment of directories, criteria, guidelines, and procedures and coordination of design, relative to the protection associated with the bulk power systems. In addition, the TFSP provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on System Protection activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "I*dentification and Assessment of Emerging Risks to Reliability*." A related contributing activity to ERO Goal No. 3 is to "Engage industry, forums, and technical committees in identifying and mitigating risks, including reducing misoperations, AC equipment failures, vegetation-related outages, and improving cold weather preparedness and human performance." A related contributing activity to ERO Goal No. 4 is to "Evaluate the reliability impacts of distributed energy resources on planning, operations and restoration and recovery, including the identification of data and information sharing needs."

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Assess proposed protection systems and special protection systems for compliance with Directory No. 4 and Directory No. 7;
- ✓ Participate or serve as lead Task Force in the implementation of applicable Regional NERC Reliability Standards;
- ✓ Review and respond to Questions, Requests for Interpretations and/or Clarifications related to bulk power system protection requirements in NPCC Directories and Criteria, as needed;
- ✓ Through the SP-7 Working Group, review misoperations of protection systems and Remedial Action Schemes/Special Protection Systems as they occur in the NPCC Region and participate in providing the NPCC input for the NERC Section 1600 Data Request.
- ✓ Review mitigations and/or progress reports for BPS Risk Reduction Implementation at each meeting and annually report to the RCC on the status of this implementation; and,
- ✓ Provide support and technical input for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee "RISC". Conduct a thorough review, provide comments as necessary and act on posted materials as directed. Task Force assessments and recommendations will be forwarded to the RCC for approval and submittal to NERC via NPCC Staff and the NERC Risk Control Process.

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Conduct review/development of the following Documents:
  - Directory No. 7 – "*NPCC Special Protection Systems*." Serve as the lead Task Force working in conjunction with the TFCP and the TFSS on revisions to ensure consistency with the development of the PRC-01202 NERC standard on Remedial Action Schemes.
  - Through the SP-9 Working Group on Telecommunication Circuits Used For Teleprotection and Remidial Action Schemes, develop a new guideline for tele-protection communication reliability.
- ✓ Participate in the ongoing development and submission of NPCC inputs/comments into the development of bulk electric system protection related NERC Reliability Standards;
- ✓ Through the SP-7 Working Group, maintain ongoing log of protection relay failures. Coordinate improved data gathering of relay failures among equipment owners, manufacturers, and vendors;
- ✓ Review and analyze the performance of protection systems of power system disturbances, lessons learned, and events inside as well as outside NPCC as brought to the attention of TFSP by the SP-7 Working Group, NERC Event Analysis Coordinating Group or as requested by the RCC. Issue recommendations for changes to NPCC Documents and lessons learned, as appropriate; and,

- ✓ Support NERC's effort through the ERO-RAPA group to continue relay misoperations performance analysis to reduce protection system misoperations and inform the RCC on relay misoperations trends, and share good practices.

TFSP Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Consistent with the TFSP's scope, conduct joint meeting with other Regions to share best practices and experiences.

Task Force on Coordination of Operation

The NPCC Task Force on Coordination of Operation (TFCO) facilitates the coordination of operations among the NPCC Reliability Coordinator areas and adjacent NERC Regions to enhance the reliability of the bulk power system. In addition, the TFCO provides technical support regarding operating expertise to the NPCC Regional Standards Committee and the NPCC Compliance Committee, and provides support and technical input for related BES risks identified by the NERC Reliability Issues Steering Committee (RISC) and the NERC Essential Reliability Services Working Group.

The Task Force on Coordination of Operation activities indicated below are done in support of ERO Goal No. 3 "*Identification and Assessment of Significant Risks to Reliability*" and ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability.*" Related contributing activities related to ERO Goal No.3 include "Conduct assessments of system resiliency and develop guidance for operations in a more secure state;" and ERO Goal No.4 "Evaluate the reliability impacts of distributed energy resources on planning, operations and restoration and recovery, including the identification of data and information sharing needs."

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Prepare and conduct the spring and autumn NPCC System Operator Seminars. Provide recommendations to enhance the programs;
- ✓ Develop and securely disseminate the annual compilation of "Facilities for Notification";
- ✓ Support and take part in a biennial, continent-wide Grid Security Exercise (GridEx), including a review of the associated reports and Lessons Learned;
- ✓ Support an annual enhanced, wide area restoration drill among the Reliability Coordinator areas of NPCC and their neighboring Reliability Coordinators incorporating the annual review of the NPCC regional restoration plan;
- ✓ Conduct pre-seasonal NPCC Reliability Assessments incorporating multi-area probabilistic reliability simulation results in each assessment. Coordinate the NPCC input for the annual data for seasonal short-term NERC Reliability Assessments;
- ✓ Conduct reviews of applicable NPCC Directories, Criteria, Guides and Procedures in accordance with their applicable review dates;
- ✓ Coordinate system awareness among NPCC RCs through periodic conference calls. This includes the existing emergency preparedness, NPCC weekly and daily system operator conference calls; and,
- ✓ Monitor the trends and impacts of the changing resource mix and the effects of the proliferation of the new resources on real-time operations, particularly the measures identified in the Essential Reliability Services Framework Report, as well as behavior during and impacts on recovery and restoration plans including consideration of distributed resources, considering the variable and energy-limited nature of the resource shifts.

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review a biennial summary of operating tool failures and lessons learned for the preceding study period;
- ✓ Provide assistance to the NERC Event Analysis process (EAP). Evaluate the operational applicability of Lessons Learned from the NERC EAP; and,
- ✓ Keep informed of the NERC Operating Committee and other subcommittee activities to determine their impact on the NPCC and any potential adjustments to Criteria, as well as provide feedback and input to the respective committees.

TFCO Reliability Assessment and Performance Analysis 2018 Goals and Deliverables

- ✓ Review and analyze the performance of Simultaneous Activation of Reserve (SAR) implementation following an event to enhance the SAR process; and,
- ✓ Share lessons learned among training staff from the NPCC RCs and utilize to make training program enhancements.

NPCC Regulatory/Governmental Affairs Advisory Group

The purpose of the NPCC Regulatory/Governmental Affairs Advisory Group is to promote NPCC interaction and coordination with Federal/State/Provincial governmental and/or regulatory agencies on a coordinated Regional basis, and identify and develop policy input for NPCC and Northeast Regional governmental and/or regulatory bodies.

The NPCC Governmental/Regulatory Affairs Advisory Group provides a forum where industry and governmental and/or regulatory representatives can exchange views and strive to develop consensus policy recommendations on reliability issues specific to the NPCC Region (Northeastern United States and Eastern Canada) and share actionable information among NPCC, NERC and other related governmental and/or regulatory agencies related to Regional energy and reliability matters.

The Regulatory/Governmental Affairs Advisory Group activities indicated below are done in support of ERO Goal No. 4 “Identification and Assessment of Emerging Risks to Reliability.” A related contributing activity to this Goal is to “Educate policy makers, regulators, and the industry of reliability effects and interconnection requirements for the changing resource mix.”

NPCC Regulatory/Governmental Affairs Advisory Group 2018 Goals and Deliverables

- ✓ Continued outreach to NPCC’s state electricity and environmental regulators stressing the importance of understanding and considering reliability impacts during the development of State/Provincial initiatives (such as the identified Essential Reliability Services). This includes focus on initiatives concerning regional planning, distributed energy resource requirements, the timing of new generation resources and transmission infrastructure projects.

Based on the portion of professional/technical staff time and other resources devoted to Reliability Assessment and Performance Analysis, NPCC estimates that it will expend 22% of its resources on these activities.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Reliability Assessment and Performance Analysis Program

Funding sources and related expenses for the Reliability Assessment and Performance Analysis section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
Reliability Assessment and Performance Analysis

		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ 3,206,966	$ 3,206,966	$ -	$ 3,225,570	$ 18,604
	Penalty Sanctions	-	-	-	15,151	15,151
Total ERO Funding		**$ 3,206,966**	**$ 3,206,966**	**$ -**	**$ 3,240,721**	**$ 33,755**
	Membership Dues	-	-	-	-	-
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 3,206,966**	**$ 3,206,966**	**$ -**	**$ 3,240,721**	**$ 33,755**
Expenses						
Personnel Expenses						
	Salaries	$ 1,084,994	$ 1,084,994	$ -	$ 1,106,772	$ 21,778
	Payroll Taxes	65,373	65,373	-	65,805	432
	Benefits	214,688	214,688	-	220,007	5,319
	Retirement Costs	121,271	121,271	-	117,144	(4,127)
Total Personnel Expenses		**$ 1,486,325**	**$ 1,486,325**	**$ -**	**$ 1,509,728**	**$ 23,402**
Meeting Expenses						
	Meetings	$ 20,500	$ 20,500	$ -	$ 22,000	$ 1,500
	Travel	186,850	186,850	-	212,000	25,150
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 207,350**	**$ 207,350**	**$ -**	**$ 234,000**	**$ 26,650**
Operating Expenses						
	Consultants & Contracts	$ 413,000	$ 413,000	$ -	$ 401,640	$ (11,360)
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
	Depreciation	-	-	-	-	-
Total Operating Expenses		**$ 413,000**	**$ 413,000**	**$ -**	**$ 401,640**	**$ (11,360)**
	Total Direct Expenses	**$ 2,106,675**	**$ 2,106,675**	**$ -**	**$ 2,145,368**	**$ 38,692**
Indirect Expenses		**$ 1,125,541**	**$ 1,125,541**	**$ -**	**$ 1,134,543**	**$ 9,002**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 3,232,217**	**$ 3,232,217**	**$ -**	**$ 3,279,911**	**$ 47,694**
Change in Assets		**$ (25,251)**	**$ (25,251)**	**$ -**	**$ (39,190)**	**$ (13,939)**
Fixed Assets						
	Depreciation	$ -	-	$ -	$ -	$ -
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	(25,251)	(25,251)	-	(39,190)	(13,939)
Inc(Dec) in Fixed Assets (C)		**(25,251)**	**(25,251)**	**-**	**(39,190)**	**(13,939)**
TOTAL BUDGET (=B+C)		3,206,966	3,206,966	-	3,240,721	33,755
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ 0**	**$ 0**	**$ -**	**$ 0**	**$ (0)**

Training, Education, and Operator Certification Program

Training, Education, and Operator Certification Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	0.10	0.10	0.00
Direct Expenses	$229,785	$230,263	$477
Indirect Expenses	$19,306	$19,460	$154
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($433)	($672)	($239)
Total Funding Requirement	$248,658	$249,051	$393

Program Scope and Functional Description

The NPCC Training, Education, and Operator Certification program supports NERC Rules of Procedure Section 900. The program provides education and training necessary to understand and operate the bulk electric system. The target audience of the program is bulk power system operating personnel - including system operations personnel, operations support personnel (engineering and information technology), supervisors and managers, and training personnel. NPCC staff training and development is incorporated within each respective program area.

Training Program Background and Description

This NPCC Program establishes and coordinates training for system operators relating to inter-Reliability Coordinator area matters, criteria, terminology, standards and operating procedures and instructions. It includes development and execution of training seminars, held twice yearly, at which: 1) potential operational problems for the coming season are discussed, 2) application of NPCC Directory and NERC Standard requirements pertinent to operation are discussed, 3) major industry issues that are important for system operators are discussed, 4) significant disturbances are reviewed for lessons learned and 5) table-top drills and communication and coordination exercises are conducted. The seminars promote camaraderie and better communication among system operators from the NPCC Reliability Coordinator (RC) areas and the Nova Scotia Balancing Authority (BA) area.

This Program also provides for: 1) sharing of RC/BA existing training program and system simulator area content; 2) training techniques and methods; 3, 3) evaluation of new techniques and training and simulator aids as they become available; 4) opportunities to consolidate training among the NPCC RCs and BAs, which includes opportunities to share training material and training sessions; and 5) exchange of information on internal methods of system operator training.

The training activities indicated below are done in support of ERO Goal No. 5 “Effective and Efficient ERO Enterprise Operations.”. A related contributing activity to this goal is to “Acquire, engage, develop, and retain highly qualified talent with requisite technical expertise to execute the ERO Enterprise’s statutory functions.”

Funding Drivers and Reliability Benefits

- Provide two high-quality continuing education seminars for system operators;
    - System operators participating in the Seminars: 1) share their approaches to solving operational problems and learn about the characteristics of neighboring systems; 2) gain exposure to NPCC issues and current industry operational topics; 3) review recent NPCC and major external disturbances; 4) review key operational related content in NPCC Directories and NERC Standards; and 5) participate in hands-on "table top exercises" pertaining to system operational practices. PJM system operators and trainers are also invited to participate and normally attend these seminars;
    - Seminar attendees also receive Continuing Education Hours (CEHs) (normally 3.5 to 4 CEHs) and operator trainers from each RC / BA area can utilize the seminar content by including it in their internal training programs to provide CEHs to all system operators; and,
    - The seminars help to improve system operational coordination through better contact among system operators at other Reliability Coordinator areas.
- Continually review and revise the curriculum of the training seminars to better emphasize NERC Standard requirements related to system operation, NPCC wide-area operations and Regionally-specific criteria and procedures;
- Enhance the system operator's awareness and knowledge of the standards, criteria and procedures they apply in real time operation;
- Provide more sharing of new training approaches, exchange of information on internal methods of system operator selection, training material and training sessions:
    - Enhance efficiency and cost savings in the training programs in the NPCC RC / BA areas;
- Provide a forum among NPCC RC/BA areas for sharing of approaches to meet the requirements of the NERC PER standards. The sharing of approaches used by some NPCC Areas to address any changes needed to existing system operator training programs due to PER-005-2 requirements is valuable to CO-2 Working Group members.
- Implement changes needed for the NPCC Reliability Coordinator / Balancing Authority Areas to meet proposed expanded training requirement for operations support staff in PER-005-2; and,
- NPCC will conduct two Standards and Compliance workshops in 2018, for NPCC Stakeholders, for the express purpose of providing the most current and applicable information related to the development of NERC and Regional Reliability Standards and the implementation of the Compliance Monitoring and Enforcement Program (CMEP).

2018 Key Assumptions

NPCC regularly conducts seminars as well as Spring and Fall Standards and Compliance workshops specifically designed, primarily through the conduct of targeted breakout class room sessions and presentations on current industry related activities, to provide for the most efficient exchange of information between the NPCC Compliance and Standards staff and the NPCC Stakeholders. Presentations in the past have been conducted by FERC, NERC and Stakeholder representatives in addition to NPCC staff members. To supplement these workshops, NPCC is considering developing on-line webinars that will focus on a specific topic pertinent to developments related to compliance program implementation, standards development or technical issues.

NPCC also regularly conducts Spring and Fall System Operator Seminars. These seminars involve system operators from the NPCC RC/BA Areas and PJM, and are held in early May and early November.

Training, Education and Operator Certification 2018 Goals and Deliverables

- Prepare and conduct the 2018 Spring and Fall NPCC System Operator Seminars;
- Implement the PER-005-2 expanded requirements within the NPCC RC/BA Area programs; and,
- Continue collaboration and sharing of the intended RC/BA approaches, experiences and materials to task identification and training development associated with NERC Standard PER-005-2.

Training, Education and Operator Certification 2018 Goals and Deliverables

- As needed, expand the NPCC repository of training resources and learning verification activities addressing fundamental power system topics, training methods and operation procedure training exercises, which may be shared as elements of operator training in compliance with NERC Standard PER-005, "*System Personnel Training*"; and,

Develop on-line operational training webinars that focus on specific topics pertinent to related to compliance program implementation, standards development or technical issues.
Based on the portion of professional/technical staff time and other resources devoted to training, education, and operator certification, NPCC estimates that it will expend 2% of its resources on this activity.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Training, Education, and Operator Certification Program

Funding sources and related expenses for the training, education, and operator certification section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
Training, Education, and Operator Certification

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 184,658	$ 184,658	$ -	$ 184,791	$ 133
Penalty Sanctions	-	-	-	260	260
Total ERO Funding	**$ 184,658**	**$ 184,658**	**$ -**	**$ 185,051**	**$ 393**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	64,000	64,000	-	64,000	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 248,658**	**$ 248,658**	**$ -**	**$ 249,051**	**$ 393**
Expenses					
Personnel Expenses					
Salaries	$ 21,012	$ 21,012	$ -	$ 18,399	$ (2,613)
Payroll Taxes	1,396	1,396	-	1,350	(46)
Benefits	4,801	4,801	-	4,893	92
Retirement Costs	2,641	2,641	-	2,320	(321)
Total Personnel Expenses	**$ 29,850**	**$ 29,850**	**$ -**	**$ 26,963**	**$ (2,888)**
Meeting Expenses					
Meetings	$ 186,300	$ 186,300	$ -	$ 188,300	$ 2,000
Travel	13,635	13,635	-	15,000	1,365
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 199,935**	**$ 199,935**	**$ -**	**$ 203,300**	**$ 3,365**
Operating Expenses					
Consultants & Contracts	$ -	$ -	$ -	$ -	$ -
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Direct Expenses	**$ 229,785**	**$ 229,785**	**$ -**	**$ 230,263**	**$ 477**
Indirect Expenses	**$ 19,306**	**$ 19,306**	**$ -**	**$ 19,460**	**$ 154**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 249,091**	**$ 249,091**	**$ -**	**$ 249,723**	**$ 632**
Change in Assets	**$ (433)**	**$ (433)**	**$ -**	**$ (672)**	**$ (239)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(433)	(433)	-	(672)	(239)
Inc(Dec) in Fixed Assets (C)	**(433)**	**(433)**	**-**	**(672)**	**(239)**
TOTAL BUDGET (=B+C)	248,658	248,658	-	249,051	393
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (0)**	**$ (0)**	**$ -**	**$ 0**	**$ 0**

Situation Awareness and Infrastructure Security Program

Situation Awareness and Infrastructure Security Program Resources (in whole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	4.00	5.00	1.00
Direct Expenses	$1,188,137	$1,373,791	$185,654
Indirect Expenses	$772,241	$973,021	$200,780
Other Non-Operating Expenses	$0	$0	$0
Inc(Dec) in Fixed Assets	($17,325)	($33,611)	($16,286)
Total Funding Requirement	$1,943,053	$2,313,202	$370,148

Program Scope and Functional Description

The Situation Awareness and Infrastructure Security Program is the combination of near real time awareness of conditions on the bulk power system with the programs necessary to increase the physical and cyber security of the electricity infrastructure, including the operation and maintenance of tools and other support services for the benefit of Reliability Coordinators and the system operators within the registered entities. Maintaining the real-time awareness of conditions on the interconnected bulk power systems by the NPCC Reliability Coordinator is critical to maintaining reliable operation within NPCC, including the communication of information concerning system conditions and abnormal events among the neighboring system operators responsible for the reliable operation of the bulk power systems. When a disturbance does occur, it is critical to use the event as a learning opportunity and provide a forum for the active coordination of reliability and operation among the NPCC Reliability Coordinator areas and neighboring NERC Regions to enhance the reliability of the interconnected bulk power system through the lessons to be learned which can be gleaned from such an event.

These Situation Awareness and Infrastructure Security activities indicated below are done in support of ERO Goal No. 3 "*Identification and Mitigation of Significant Risks to Reliability*." A related contributing activity to this Goal is to "Analyze system performance, events, and relationships among data sources to identify risks and mitigation strategies, and provide recommendations and lessons learned."

Event Analysis Program Description

NERC and the industry follow three avenues in the analysis of a disturbance: the identification of lessons to be learned, a formal cause code analysis and a review of applicable standards.

The Event Analysis Program recognizes that many events which occur on the bulk power system beyond those identified through NERC Reliability Standard EOP-004-2, "Event Reporting," can have varying levels of significance to the electric system, providing otherwise unrealized lessons to be learned from these events and the trending of such events to identify possible reliability concerns. By integrating a "bottom-up" approach to a disturbance review within the framework of the NERC Event Analysis Program, consistency, comparability, flexibility and timeliness in the event analysis process will be promoted by NPCC, the registered entities and NERC in a collaborative initiative. Upon the identification of an event, the goal of the Event Analysis Program is to:

- identify what transpired;
- categorize the event within the NERC Event Analysis Program;
- establish the sequence of events;
- understand the essential root causes of the event;
- identify recommendations or corrective actions; and,
- develop and disseminate to the industry lessons to be learned so that the operational reliability of the bulk power system can be further enhanced.

In assessing any system event, it is recognized that, if the timely dissemination of lessons learned from an event or disturbance is to be realized, any potential compliance implications associated with an event must be addressed and dismissed. Throughout an event analysis effort, to make this process successful and complete, and to solidify the "bottom-up" approach, registered entities are encouraged to establish a liaison between the event analysis and compliance functions internal to the registered entity during the event analysis process. This serves to facilitate the development of a registered entity compliance self-assessment report which will perform a sufficiency review of the reliability standards deemed applicable to the event, assisting in the self-reporting of possible violations should any be discovered.

To complete this effort, the entity, the Region and NERC staff will collaborate to assess the NERC Event Analysis Report and perform a formal cause code analysis, identifying a root cause and publish any pertinent lessons learned gathered from the disturbance.

The adoption by NERC of the Event Analysis Program brings clarity and certainty about what system events are relevant to analyze and to what level of detail, targeting potential risks to the reliability of the bulk power system for detailed and in depth analysis; only concise and succinct reviews are desired for more minor events. It also delineates the expectations of roles and responsibilities of the registered entities, NPCC and NERC in a uniform review of system disturbances by the industry, and, ultimately, the program promotes the timely development and dissemination of valuable lessons learned to the industry. The identification and tracking of emerging common risks through the assessment of events will further distinguish trends which may be of concern to reliability. By rigorously pursuing the lesser events on the system and learning from these disturbances, larger events can be avoided or mitigated.

NPCC staff works step-by-step with the registered entity in the total event analysis process, permitting the entity to assume the primary role in the development of the initial analysis, lessons learned which may benefit the industry and the Standards sufficiency review and cause coding for trending and reporting. NPCC staff, throughout the process, guides, supports and stands as an advocate of the registered entity as they continue to develop an improved culture of reliability and compliance.

2018 Key Assumptions

- The monitoring of Lessons Learned will continue to be a major focus of NERC in 2018. This will include an added aspect of the voluntary Event Analysis Program, in response to a recommendation of the AC Substation Equipment Task Force (ACSETF), to solicit and collect detailed information on station equipment failures, for applicable, qualifying events to aid in future analysis of station equipment failures to identify trends that may be a threat to the reliability of the BES;
- Critical infrastructure protection will fully integrate the requirements of Version 5 of the Cyber Standards in 2018; and,

- NERC will post updates to the critical infrastructure protection (CIP) Standards to address the three FERC Directives and the four industry concerns that were not satisfactorily responded to by the version 5 Transition Advisory Group.

Situation Awareness 2018 Goals and Deliverables

NERC Activities

- NPCC will provide the Regional perspective and support through NPCC EA staff participation on selective NERC Planning and Operating Committees and key related NERC Subcommittees, Task Forces and Working Groups, including:
  Event Analysis Subcommittee (EAS);
  ERO – EA/SA Group; and,
  The Event Analysis Management System (TEAMS).

NPCC Activities

- Work directly with applicable NPCC Task Forces to provide an in-depth assessment of Lessons Learned unique to the NPCC members and NPCC Criteria;
- Promote NPCC's Event Analysis group's established process for sharing and dissemination of the detailed Event Analysis Report information among industry participants (registered entities);
- Incorporating the Lessons Learned from participation in the GridEx IV wide-area exercise;
- Utilize the NPCC's "what if" methodology to examine an event's potential impact under a different set of system conditions, to evaluate the proximity of a particular event to being a significant BPS requiring appropriate level of analysis with due weight to risk and impact;
- Establish a process/procedure for data capture and transfer aspects for post-disturbance (major disturbance and/or blackout events) system analysis, including requirements for regularly scheduled (annual) testing of the procedure implementation;
- Monitor the operational status of the bulk power system and coordinate normal and pre-emergency communication, awareness and assistance in addition to the same during an emergency among the Reliability Coordinators (RCs) within NPCC. Notify the RCs of significant bulk power system events that have occurred in one Reliability Coordinator Area, and which have the potential to impact reliability in other NPCC Reliability Coordinator Areas or Regions external to NPCC. These events include contingencies on the bulk power system, potential shortfalls of operating reserve, operating problems, potential security threats and potential threats or disruptions to the cyber systems;
- Conduct a daily conference call to serve as a complement to the NPCC Emergency Preparedness Conference Call. The participants of the call are the Reliability Coordinators within NPCC and its neighboring RCs, the Midcontinent ISO and PJM. The conference call is implemented through a bridge, the initiation of the call quickly ringing all pre-selected telephones simultaneously. The goal of the call is to alert all Reliability Coordinators of emerging problems. If no system difficulties are anticipated for the day, no unnecessary information is to be discussed. Subjects for discussion are limited to credible events which could impact the ability of an entity to serve its load and meet its operating reserve obligations or would impose a burden to the interconnection, including the following: Projected Load; Adverse Weather; Operating Reserve; Generation; Transmission; and Sabotage. If conditions worsen in the course of the day, the NPCC Emergency Preparedness Conference Call will be implemented;
- Monthly test of the satellite telephone network, to ensure the capability for continued voice communications among NPCC and its Reliability Coordinators. This back-up communications system will function in the event of a collapse of the Public Switched

Telephone Network (PSTN), permitting continued cross-border voice communications among the Canadian Reliability Coordinators of NPCC, the Reliability Coordinators in the United States as well as NPCC Situation Awareness (SA) staff.

Situation Awareness 2018 Goals and Deliverables

Monitor the status of the bulk power system through the NERC Situational Awareness-FERC, NERC, Regions (SAFNR) initiative, a near real-time operating display for the United States portion of the Reliability Coordinators footprints of North America. Transmission voltage levels of 230 kV and above are displayed, and the tool provides the ability to "drill down" to detailed bus information, including generation outputs and bus voltages.

Critical Infrastructure Objectives

NPCC's critical infrastructure objectives are defined within the scope of the NPCC Task Force on Infrastructure Security & Technology, (TFIST) and include, but are not confined to:

- Providing a forum for NPCC review of proposed and posted documents from the NERC Critical Infrastructure Protection Committee (CIPC); and,
- Representing and advocating NPCC's position in the activities of NERC groups involved in the development and/or implementation of physical and cyber security.

NPCC's 2018 critical infrastructure goals and objectives, supporting ERO Goal No. 3 - *Identification and Mitigation of Significant Risks to Reliability*." Related contributing activities to this Goal include "Expand the use, availability, and value of physical security and cybersecurity threat and vulnerability information sharing, including cross sector communications, and analytics" and "In collaboration with the Critical Infrastructure Protection Committee and industry stakeholders, develop a risk process to address the potential impact of cyber and physical security threats and vulnerabilities."

Critical Infrastructure 2018 Goals and Deliverables

- Monitor the reliable implementation of the Cyber Security Standards;
- Monitor the Homeland Security Information Network (HSIN), E- ISAC, NERC Alerts and Canadian Information Sharing and share information with the NPCC CO-8 Working Group;
- Review and submit comments on NERC proposed Reliability Standards, modified Reliability Standards, proposed Guidelines and modified Guidelines related to Infrastructure Security and Technology;
- Keep current on all governmental agencies regarding applicable security recommendations and requirements, and other applicable security and reliability recommendations and keep the RCC and its committees appropriately informed, e.g. Sector Specific Plan;
- Conduct an annual test of cross border emergency telecommunications to verify each Area can communicate with each other;
- Provide support and technical input for Task Force related BES risks as identified by the NERC Reliability Issues Steering Committee "RISC." The Task Force will conduct a thorough review, provide comments as necessary and act on posted materials as directed; and,
- Support the NERC CIPC Grid Exercise Working Group (GEWG) with Cross Sector support in Grid Exercise (GridEx) IV planning and simulation. Participate in the development of lessons learned from GridEx IV.

Critical Infrastructure 2018 Goals and Deliverables

- Review infrastructure security & technologies and provide recommendations to enhance physical and cyber security in compliance with NERC guidelines/standards;
- Provide recommendations to enhance physical and cyber security, in compliance with NERC standards, based on assessments of available and emerging infrastructure security technologies, methodologies, and best practices;
- Sponsor periodic workshop presentations to address timely issues and update NPCC Members associated with infrastructure security and technology.; and,
- Provide education, awareness, and support for Cross Sector coordination in Entity agreements and response plans with focus upon Telecommunications, Water and Natural Gas, including monitoring and sharing with the E-ISAC.

Related System Operations Security 2018 Goals and Deliverables

NPCC's system operations security objectives are defined within the scope of the NPCC Task Force on Coordination of Operation (TFCO) and include, but are not confined to:

- Coordinating inter-Regional pre-emergency actions in the event of a threat to the security of the Northeastern North American bulk power supply system; and,
- Assisting in the development of real time operating tools assuring cyber security concerns are addressed.

2018.Based on the portion of professional/technical staff time and other resources devoted to situation awareness and infrastructure security, NPCC estimates that it will expend 16% of its resources on this activity.

Resource Requirements

Personnel

- Reallocation of staff during 2017 resulted in an increase of one full time employee in the Situation Awareness and Infrastructure Security program to support increased workload in this area.

Consultants and contracts

- Decrease in consulting and contracts expense is associated with increase in staff allocated to this program area.

Situation Awareness and Infrastructure Security Program

Funding sources and related expenses for the situation awareness and infrastructure security section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
Situation Awareness and Infrastructure Security

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ 1,943,053	$ 1,943,053	$ -	$ 2,300,208	$ 357,155
Penalty Sanctions	-	-	-	12,994	12,994
Total ERO Funding	**$ 1,943,053**	**$ 1,943,053**	**$ -**	**$ 2,313,202**	**$ 370,148**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ 1,943,053**	**$ 1,943,053**	**$ -**	**$ 2,313,202**	**$ 370,148**
Expenses					
Personnel Expenses					
Salaries	$ 660,213	$ 742,713	$ 82,500	$ 825,560	$ 165,347
Payroll Taxes	42,778	50,278	7,500	53,677	10,899
Benefits	160,814	173,564	12,750	189,417	28,603
Retirement Costs	72,333	83,583	11,250	87,637	15,304
Total Personnel Expenses	**$ 936,137**	**$ 1,050,137**	**$ 114,000**	**$ 1,156,291**	**$ 220,154**
Meeting Expenses					
Meetings	$ 13,500	$ 13,500	$ -	$ 10,000	$ (3,500)
Travel	78,500	85,250	6,750	87,500	9,000
Conference Calls	-	-	-	-	-
Total Meeting Expenses	**$ 92,000**	**$ 98,750**	**$ 6,750**	**$ 97,500**	**$ 5,500**
Operating Expenses					
Consultants & Contracts	$ 160,000	$ 160,000	$ -	$ 120,000	$ (40,000)
Office Rent	-	-	-	-	-
Office Costs	-	-	-	-	-
Professional Services	-	-	-	-	-
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Depreciation	-	-	-	-	-
Total Operating Expenses	**$ 160,000**	**$ 160,000**	**$ -**	**$ 120,000**	**$ (40,000)**
Total Direct Expenses	**$ 1,188,137**	**$ 1,188,137**	**$ 120,750**	**$ 1,373,791**	**$ 185,654**
Indirect Expenses	**$ 772,241**	**$ 772,241**	**$ -**	**$ 973,021**	**$ 200,780**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ 1,960,378**	**$ 1,960,378**	**$ 120,750**	**$ 2,346,812**	**$ 386,434**
Change in Assets	**$ (17,325)**	**$ (17,325)**	**$ (120,750)**	**$ (33,611)**	**$ (16,286)**
Fixed Assets					
Depreciation	$ -	-	$ -	$ -	$ -
Computer & Software CapEx	-	-	-	-	-
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	(17,325)	(17,325)	-	(33,611)	(16,286)
Inc(Dec) in Fixed Assets (C)	**(17,325)**	**(17,325)**	**-**	**(33,611)**	**(16,286)**
TOTAL BUDGET (=B+C)	1,943,053	1,943,053	120,750	2,313,202	370,148
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (0)**	**$ (0)**	**$ (120,750)**	**$ 0**	**$ 0**

Administrative Services

Administrative Services Program Resources (in whole dollars)	Direct Expenses and Fixed Assets			FTEs		
	2017 Budget	2018 Budget	Increase (Decrease)	2017 Budget	2018 Budget	Increase (Decrease)
Technical Committees and Members Forum	$72,500	$70,680	($1,820)	0.50	0.50	0.00
General and Administrative	$3,245,691	$3,338,132	$92,441	2.50	2.50	0.00
Legal and Regulatory	$648,680	$592,049	($56,632)	1.00	1.00	0.00
Information Technology	$1,185,675	$1,119,490	($66,186)	2.00	2.00	0.00
Human Resources	$182,059	$181,145	($915)	1.00	1.00	0.00
Finance and Accounting	$525,262	$537,236	$11,974	1.00	1.00	0.00
Total Administrative Services	$5,859,868	$5,838,732	($21,136)	8.00	8.00	0.00

Program Scope and Functional Description

Administrative services support the previously identified five program areas of: reliability standards; compliance monitoring and enforcement and organization registration and certification; training, education, and operator certification; reliability assessment and performance analysis; and situation awareness and infrastructure security. Administrative services consist of: technical committees and members' forums; general and administrative; legal and regulatory; information technology; human resources; and finance and accounting.

Methodology for Allocation of Administrative Services Expenses to Programs

NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Administrative Services

Funding sources and related expenses for the Administrative Services section of the 2018 business plan are shown in the table below. Explanations of variances by expense category are included with the Supplemental Tables found in Section B.

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
ADMINISTRATIVE SERVICES

	2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding					
ERO Funding					
ERO Assessments	$ (185,991)	$ (185,991)	$ -	$ 15,823	$ 201,813
Penalty Sanctions	-	-	-	-	-
Total ERO Funding	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Membership Dues	-	-	-	-	-
Testing Fees	-	-	-	-	-
Services & Software	-	-	-	-	-
Workshops	-	-	-	-	-
Interest	-	-	-	-	-
Miscellaneous	-	-	-	-	-
Total Funding (A)	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Expenses					
Personnel Expenses					
Salaries	$ 1,872,579	$ 1,872,579	$ -	$ 2,063,139	$ 190,561
Payroll Taxes	93,995	93,995	-	97,378	3,383
Benefits	418,433	418,433	-	438,408	19,975
Retirement Costs	317,471	317,471	-	295,596	(21,874)
Total Personnel Expenses	**$ 2,702,478**	**$ 2,702,478**	**$ -**	**$ 2,894,522**	**$ 192,044**
Meeting Expenses					
Meetings	$ 120,000	$ 120,000	$ -	$ 116,750	$ (3,250)
Travel	143,590	143,590	-	138,000	(5,590)
Conference Calls	37,000	37,000	-	37,000	-
Total Meeting Expenses	**$ 300,590**	**$ 300,590**	**$ -**	**$ 291,750**	**$ (8,840)**
Operating Expenses					
Consultants & Contracts	$ 152,000	$ 152,000	$ -	$ 92,000	$ (60,000)
Office Rent	809,700	809,700	-	810,700	1,000
Office Costs	679,100	679,100	-	664,760	(14,340)
Professional Services	1,041,000	1,041,000	-	960,000	(81,000)
Computer & Equipment Leases	-	-	-	-	-
Miscellaneous	50,000	50,000	-	50,000	-
Depreciation	250,000	250,000	-	269,000	19,000
Total Operating Expenses	**$ 2,981,800**	**$ 2,981,800**	**$ -**	**$ 2,846,460**	**$ (135,340)**
Total Direct Expenses	**$ 5,984,868**	**$ 5,984,868**	**$ -**	**$ 6,032,732**	**$ 47,864**
Indirect Expenses	**$ (5,984,868)**	**$ (5,984,868)**	**$ -**	**$ (6,032,732)**	**$ (47,864)**
Other Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)	**$ -**	**$ -**	**$ -**	**$ 0**	**$ 0**
Change in Assets	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**
Fixed Assets					
Depreciation	(250,000)	(250,000)	$ -	(269,000)	$ (19,000)
Computer & Software CapEx	125,000	125,000	-	75,000	(50,000)
Furniture & Fixtures CapEx	-	-	-	-	-
Equipment CapEx	-	-	-	-	-
Leasehold Improvements	-	-	-	-	-
Allocation of Fixed Assets	125,000	125,000	-	194,000	69,000
Inc(Dec) in Fixed Assets (C)	**-**	**-**	**-**	**-**	**-**
TOTAL BUDGET (=B+C)	-	-	-	0	0
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)	**$ (185,991)**	**$ (185,991)**	**$ -**	**$ 15,823**	**$ 201,813**

Technical Committees and Member Forums

Program Scope and Functional Description

The success of the NPCC programs depends on the active and direct volunteerism and participation of its members. The stakeholders are the source of subject matter expertise in the industry. To promote the reliable and efficient operation of the interconnected bulk power systems in Northeastern North America, NPCC invites high level policy makers from Federal, Provincial and State regulatory and/or governmental authorities and senior executives within NPCC and NERC to identify and discuss emerging issues related to the reliability of the NPCC Region.

2018 Key Assumptions

- NPCC's standing committee and subgroup structure for effective stakeholder involvement will continue in 2018
- NPCC will continue to utilize methods to encourage active involvement in its Regional programs that require less stakeholder travel and face-to-face meetings, as the economy improves in 2018
- NPCC will continue to invest in technology and innovation to allow efficient collaboration on technical issues related to reliability

The Technical Committees and Member Forums activities indicated below are done in support of ERO Goal No. 4 "*Identification and Assessment of Emerging Risks to Reliability*." A related contributing activity to this Goal is to "Educate policy makers, regulators, and the industry of reliability effects and interconnection requirements for the changing resource mix."

Technical Committees and Member Forums 2018 Goals and Deliverables

- ✓ The 2018 NPCC General Meeting provides an opportunity for NPCC Members to meet high level policy makers from Federal, Provincial and State regulatory and/or governmental authorities and senior NERC and NPCC executives to discuss topics related to the reliable planning and operation of the power system, including consideration of emerging reliability, critical infrastructure and environmental issues; and,
- ✓ The objective of the NPCC Public Information Committee is to highlight and summarize NPCC activities and accomplishments in the past year, disseminate and coordinate the appropriate release of information to the media, respond to related requests for information, and coordinate with related NPCC Area, NERC media and public information activities. Activities anticipated include, but are not limited to:
    - Conducting the Media Event – release of the Summer 2018 NPCC Reliability Assessment; and,
    - Participation in NERC Regional communication initiatives:
        - Regional communications teleconferences as required
        - Coordination of Emergency or Blackout communications plans
        - Coordination with other NERC activities as required (i.e., situation awareness, event analysis, reliability assessments, etc.)

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

General and Administrative

Program Scope and Functional Description

The NPCC general and administrative function provides executive management of the corporation, management of NPCC office, and other administrative support programs.

NPCC total overhead expenses, such as office rent and office costs, will be charged to the Administrative Services Programs and then reallocated proportionately based on FTE to the programs through Indirect Expenses.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Office Rent

- Projected increase in real estate taxes.

Legal and Regulatory

Program Scope and Functional Description

NPCC's professional legal services provide counsel to the President and CEO, Board of Directors, Senior Vice President and COO, Treasurer, General Counsel and staff on a wide range of legal and regulatory matters including legislation, corporate law, code of conduct, confidentiality, governance, employment law, tax matters, contract law and other areas affecting NPCC. In support of ERO Goal 5.c., NPCC's in-house counsel evaluates internal controls and corporate, operational, strategic and reputational risk, and participates in risk identification, evaluation and mitigation activities. In-house counsel provides legal advice to advance significant corporate policy and strategic planning initiatives and also provide legal support to other program areas on matters arising in connection with the performance of NPCC's delegated functions. In-house counsel draft agreements and pleadings and provide interpretations of relevant statutes, regulations, court opinions, and regulatory decisions of FERC, state agencies and provincial authorities. Outside counsel, as necessary, reviews items filed with the governmental agencies for legal sufficiency, maintains relationships with U.S. and Canadian jurisdictions and provides contract review.

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Professional Services

- Legal fees are projected to be lower based on additional workload taken on by in-house legal team.

Information Technology

Program Scope and Functional Description

NPCC's Information Technology services ensure information assets and the environment in which they operate are secure and in conformance to NPCC IT Policies and Procedures and all applicable Critical Electric Infrastructure Information protection and Confidentiality requirements. NPCC maintains an offsite backup server for continuity of essential operations in the event that its primary location is unavailable.

NPCC supports the ERO efforts to implement, operate and maintain software tools supporting common enterprise wide operations and leveraging ERO solutions which have been approved by the ERO Executive Management Group (ERO EMG), which is comprised of the senior leadership of NERC and each of the Regional Entities. NPCC's budget assumes the availability of enterprise software tools as described in NERC's business plan and budget. If implementation of these software applications is delayed or otherwise not available as planned, NPCC could incur additional costs to implement ERO Enterprise-wide programs pending the availability of these applications.

NERC and the Regional Entities are committed to working collaboratively to minimize duplication of effort and investments, and improve operational efficiency. This collaboration continues to refine existing strategies, governance and procurement practices applicable to the development, operation and maintenance of enterprise architecture, software and data systems supporting complementary and combined NERC and Regional Entity operations.

The NERC information technology budget does not supplant NPCC's need for IT expenditures for specific regional projects and internal region specific IT support needs. NPCC's 2018 Business Plan and Budget assumes agreed-upon ERO Enterprise applications will be available and includes only NPCC costs for region specific support needs.

2018 Key Assumptions

- Continue to maintain the compliance portal through collaboration with other Regional Entities and NERC (CUG).
- Support the Event Analysis program through continued participation in the tools used for the tracking and analysis of system events and identification of better practice elements.
- Support the Bulk Electric System Exception Process (BEP) to enable and facilitate tracking and processing of exceptions submitted. Maintenance of the BESNET support services such as updates, patching, coordinating issues with NERC.
- Support Cyber Security Reviews done by Compliance to provide advisory role during those reviews.

2018 Goals and Key Deliverables

Responsibilities encompass a variety of complex technical, administrative, and supervisory work in the development, installation, and maintenance of information technology systems. IT goals include, but are not limited to:

- Expand the utilization of the document management system throughout the company.
- Create an information security program and environment aimed at reducing breach of security risks
- Determine longer-term software and systems needs and hardware acquisitions
- Develop and implement information security standards and procedures

- Ensure all information systems are functional and secure, and that all applications running on those systems meet business requirements for performance, availability, and security
- Plan and implement organization-wide information systems, services, and network facilities, including local area networks, wide-area networks, and peripheral systems
- Provide outreach and education to NPCC members in IT best practices
- Continually improve Disaster Recovery and Business Continuity policies and practices to ensure continuity and reliability of IT and business related services

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Human Resources

Program Scope and Functional Description

NPCC has assembled an exceptional team of highly qualified employees to carry out the activities of NPCC. The human resources function, in adherence with applicable federal and state laws, designs, plans, and implements human resources policies and procedures, including: staffing; compensation; benefits; employee relations; training and development; and employee time tracking.

Resource Requirements

Personnel

- Temporary office services increased to assist in administrative services in the area of human resources.

Accounting and Finance

Program Scope and Functional Description

The accounting and finance function directs the overall financial plans and accounting practices of the organization; oversees treasury, accounting, budget, tax, and audit activities; and oversees financial and accounting system controls and standards. NPCC uses a CPA firm to prepare its unaudited statements of activities and financial statements for quarterly reviews. Independent audits have identified this system as a best practice.

2018 Goals and Key Deliverables

The objectives are to provide or obtain the financial and accounting services for NPCC and coordinate with NERC requirements:

- Utilize the NERC System of Accounts for consistency
- Utilize an accrual method of accounting for consistency with NERC in methodology
- Alignment of changes in budget and changes in aggregate assessment
- Cash Management
- Budget Development using the NERC budget template formats
- Forecasts and Projections
- Alignment of NPCC Committees, Task Forces and Working Groups with the programs
- Payroll and expense administration
- Preparation of unaudited Quarterly Financial Variance Reports
- IRS Reporting
- Annual Independent Audit initiated by the Regional Entity

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

Regional Entity Assessment Analysis

In the area of assessments there are distinct funding mechanisms as outlined in the following table. For the Regional Entity division, the North American Electric Reliability Corporation (NERC) will assess load serving entities (LSEs) or their designees (within NPCC the designees are the Balancing Authority Areas (BAAs) for New York, New England, New Brunswick, Nova Scotia, Ontario and Québec) based upon 2016 proportional Net Energy for Load (NEL) and other specific program area funding arrangements and make quarterly remittances to the Regional Entity on or about the 15th day of January, April, July and October. For funding associated with the criteria services division, the Independent System Operators/Balancing Authority Areas (ISO/BAAs) will be assessed by NPCC for their proportional share of the divisional budget based upon 2016 NEL within the Region. Non ISO/BAA Full Members will be assessed no membership fee.

NPCC Cost Allocation Methodology

The accompanying table provides information regarding cost allocation for both the Regional Entity division and the criteria services division of NPCC, including the details associated with the funding of the Compliance Program within the RE division. For purposes of determining assessments to support NPCC's resource requirements, costs are allocated among the BAAs within NPCC as the designees for the load-serving-entities in New York, New England, Ontario, Québec, New Brunswick and Nova Scotia.

In order to reflect and respect the international membership and nature of NPCC, any sub-regional reliability assessment costs in response to U.S. only regulatory initiatives will be considered for allocation to U.S. only BAAs consistent with NERC Rules of Procedure section 1102. Additionally, the compliance responsibilities and authorities within the U.S., and the specific compliance responsibilities within each of the Canadian provinces within NPCC, and the attendant costs of portions of the compliance program differ among the areas within the Regional Entity. Within the U.S. portion of NPCC all costs attributable to delegated (statutory) functions performed by NPCC, including all compliance functions, are assessed based on a NEL allocation. Within the Canadian portion of NPCC those costs attributable to compliance functions performed by NPCC on behalf of provincial governmental and/or regulatory authorities are allocated consistent with the unique Memoranda of Understanding or Agreements that have been entered into for those provinces. To address these different compliance regimes, NPCC developed a composite cost allocation methodology that allocates U.S. only reliability assessment and compliance costs on a fair and equitable basis within the Regional Entity.

As an initial step of that methodology, the NEL for each of the BAAs and their relative percentage to the NPCC total NEL is calculated for the most recent year for which data is available, the second previous year. In order to establish the RE division funding requirements for each Balancing Authority Area on a NEL basis for all programs except for Compliance, the proposed expenses and fixed assets of all other programs are calculated and the adjustment for the RE division cash reserve requirement is identified. Any penalty monies received from NPCC registered entities within the U.S. prior to June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs. Consistent with each of the Canadian provincial MOUs and agreements, all penalty monies resulting from compliance actions within Canada, if any, would remain within the applicable province. The total budgeted fees for NPCC

workshop participation are indicated as a credit, with the resultant addition being the RE division assessment, without the compliance program costs, calculated on a NEL basis.

In accordance with the *NPCC Amended and Restated Bylaws* the CS division proposed expenses and fixed assets of all programs are calculated and the adjustment for the CS division cash reserve requirement is identified, with the resultant addition being the CS division funding requirement and assessment, calculated on a NEL basis

For costs associated with the RE division compliance program, NPCC's allocation methodology apportions XX% of the costs for the program, attributed to CORC Fundamentals (CF), between the BAAs in the United States and Canada on a NEL basis.

Audits and Investigations (AI) related costs, representing XX% of the costs of the compliance program, are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an audit-based methodology. The audit-based methodology incorporates relative costs based on categories of compliance audits which are reflective of their size and complexity, as well as the differing compliance program implementation models that are utilized in NPCC due to the international nature of the Regional Entity. The portion allocated to the U.S. BAAs in NPCC is calculated using the audit-based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

The remaining XX% of the costs of the compliance program represent Mitigation and Enforcement (ME) related costs and are allocated between U.S. and Canadian BAAs in NPCC, and among the Canadian provinces, using an enforcement activity based methodology. Based on historical data, NPCC reviewed each BAAs percentage of violations, mitigation plans and settlement agreements to determine each BAAs total average percentage of enforcement activities. The portion allocated to the U.S. BAAs in NPCC is calculated using the enforcement activity based methodology, and this amount is then re-allocated between the New York and New England BAAs based on their relative NEL.

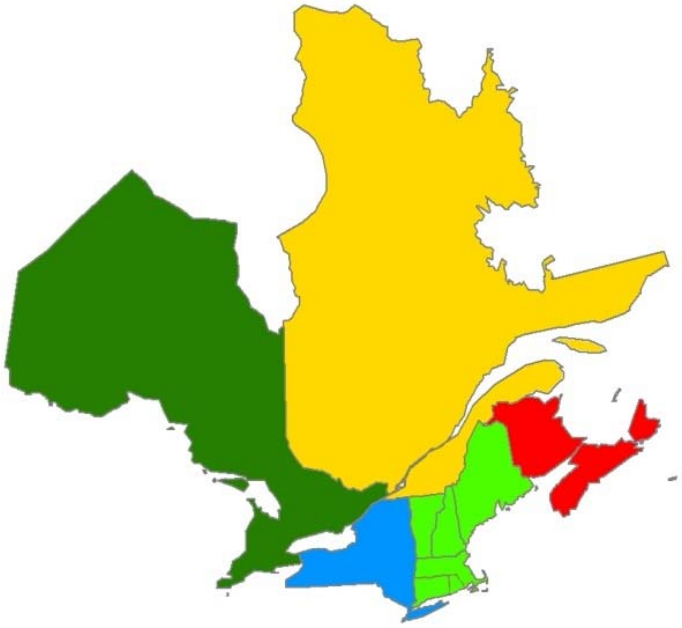
Any penalty monies received from NPCC registered entities within the U.S. by June 30th of the year preceding the business plan and budget year are then allocated among the NPCC program areas based on their FTE ratio and between the U.S. BAAs based on their relative NELs, and then added to the total compliance program expenses and fixed assets to yield a total compliance program assessment.

The CORC actual vs budget variance from the most recent year for which audited financials are available is broken out from the rest of the Adjustment to Cash Reserve and assigned to the CORC program allocation of costs. Within Quebec these costs are funded directly by the regulator, therefore, the assignment of program area variances needs to respect those specific circumstances.

Finally, the total RE division funding requirements and assessments by BAA are tabulated and the total funding requirements and assessments for NPCC, both the RE and CS divisions, are combined.

Table to be Inserted

Section B – Supplemental Financial Information
2018 Business Plan and Budget



Section B — Supplemental Financial Information

Reserve Balance

Table B-1 Reserve Balance

Working Capital and Operating Reserve Analysis 2017-2018
REGIONAL ENTITY DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Working Capital and Operating Reserve, December 31, 2016	5,327,887	4,069,023	1,258,864	0
Plus: 2017 ERO Funding (from LSEs or designees)	14,255,061	14,255,061		
Plus: 2017 Other funding sources	64,000	64,000		
Less: 2017 Projected expenses & capital expenditures	(15,147,054)	(15,147,054)		
Projected Working Capital and Operating Reserve, December 31, 2017	**4,499,893**	**3,241,030**	**1,258,864**	**0**
Desired Working Capital and Operating Reserve, December 31, 2018 [1]	**2,933,713**	1,674,849 [2]	1,258,864 [3]	
19.42% of Total Regional Entity Budget of $15,106,967				
Desired Business Continuity Reserve, December 31, 2018 [4]	**940,000**			940,000
Less: Projected Working Capital and Operating Reserve, December 31, 2017	(4,499,893)	(3,241,030)	(1,258,864)	
Increase(decrease) in assessments to achieve desired Total Reserve	**(626,180)**	(1,566,180)	0	0

2018 Expenses and Capital Expenditures	15,106,967
Less: Penalty Sanctions [5]	(75,000)
Less: Other Funding Sources	(64,000)
Adjustment to achieve desired Total Reserve balance	(626,180)
2018 Assessment	**14,341,787**

[1] Total Reserve within a range of 16.67% - 33.33% of Budget.
[2] Operating Reserve within a range from 8.33% to 25.00% of Budget. $1,674,849 represents 11.09% of the 2017 budget of $15,106,967
[3] Working Capital equal to 8.33% of Budget. $1,258,864 represents 8.33% of the 2017 budget of $15,106,967
[4] Establish Business Continuity Reserve as approved by the NPCC Board of Directors upon recommendation by the MDCC.
[5] Represents collections July 1, 2016 to June 30, 2017.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy, however, a separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established as approved by the NPCC Board of Directors, upon recommendation by the Management Development and Compensation Committee and endorsement by the Finance and Audit Committee, to be identified as restricted cash and drawn upon as subsequently brought before the Board of Directors in association with President & CEO succession related activities associated with a planned or sudden retirement, as well as other sudden changing workforce staffing requirements.

Breakdown by Statement of Activity Sections

The following detailed schedules are in support of the Regional Entity division Statement of Activities on page 13 of the 2018 Business Plan and Budget. All significant variances have been disclosed by program area in the preceding pages.

Penalty Sanctions

U.S. penalty monies received prior to June 30, 2017 are to be used to offset assessments in the 2018 Budget, as documented in the NERC Policy – Accounting, Financial Statement, and Budgetary Treatment of Penalties Imposed and Received for Violations of Reliability Standard. Penalty monies received from July 1, 2017 through June 30, 2018 will be used to offset U.S. load serving entity designee assessments in the 2018 Budget.

Allocation Method: U.S. penalty sanctions received have been allocated to the following Regional Entity division programs to reduce assessments: Reliability Standards; Compliance Monitoring & Enforcement and Organization Registration & Certification; Reliability Assessments and Performance Analysis; Training, Education and Operator Certification; and Situation Awareness and Infrastructure Security. U.S. penalty sanctions are allocated based upon the number of FTEs in the Program divided by the aggregate total FTEs in the Programs receiving the allocation.

Table B-2 Penalty Sanctions

Penalty Sanctions Received Prior to June 30, 2016	Date Received	Amount Received
Penalty Payment 1	12/16/2016	$ 75,000.00
Total Penalties Received		**$ 75,000.00**

Table B-3 Supplemental Funding

Outside Funding Breakdown By Program (excluding ERO Assessments & Penalty Sanctions)	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget
Reliability Standards				
Total	$ -	$ -	$ -	$ -
Compliance Monitoring, Enforcement & Org. Registration				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Reliability Assessment and Performance Analysis				
	$ -	$ -	$ -	$ -
	-	-	-	-
Total	$ -	$ -	$ -	$ -
Training and Education				
Workshops	$ 64,000	$ 64,000	$ 64,000	$ -
Total	$ 64,000	$ 64,000	$ 64,000	$ -
Situation Awareness and Infrastructure Security				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Technical Committees and Member Forums				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Administrative Services Programs				
	$ -	$ -	$ -	$ -
Total	$ -	$ -	$ -	$ -
Total Outside Funding	$ 64,000	$ 64,000	$ 64,000	$ -

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- NPCC assumed no interest income because of continuing low market interest rates.

Table B-4 Personnel Expenses

Personnel Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Salaries					
Salary	$ 6,718,926	$ 6,718,926	$ 7,057,483	$ 338,557	5.0%
Employment Agency Fees	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Temporary Office Services	$ 30,000	$ 30,000	$ 40,116	$ 10,116	33.7%
Total Salaries	$ 6,758,926	$ 6,758,926	$ 7,107,599	$ 348,673	5.2%
Total Payroll Taxes	$ 404,319	$ 404,319	$ 411,440	$ 7,121	1.8%
Benefits					
Education Reimbursement	$ 22,500	$ 22,500	$ 30,000	$ 7,500	33.3%
Training and Seminars	$ 36,860	$ 36,860	$ 44,232	$ 7,372	20.0%
Medical Insurance	$ 790,034	$ 790,034	$ 811,369	$ 21,335	2.7%
Life-LTD-STD Insurance	$ 88,716	$ 88,716	$ 90,465	$ 1,749	2.0%
Worker's Compensation	$ 15,000	$ 15,000	$ 15,000	$ -	0.0%
Vacation	$ 462,494	$ 462,494	$ 485,312	$ 22,818	4.9%
Relocation	$ -	$ -	$ -	$ -	-
Total Benefits	$ 1,415,603	$ 1,415,603	$ 1,476,378	$ 60,774	4.3%
Retirement					
Pension Contribution	$ 37,000	$ 37,000	$ 38,000	$ 1,000	2.7%
Employee Savings Plan	$ 727,223	$ 727,223	$ 714,353	$ (12,869)	-1.8%
Savings Admin	$ 45,000	$ 45,000	$ 35,000	$ (10,000)	-22.2%
Deferred Compensation	$ 38,000	$ 38,000	$ 38,000	$ -	0.0%
Total Retirement	$ 847,223	$ 847,223	$ 825,353	$ (21,869)	-2.6%
Total Personnel Costs	**$ 9,426,071**	**$ 9,426,071**	**$ 9,820,770**	**$ 394,699**	**4.2%**
FTEs	36.86	36.86	36.86	-	0.0%
Cost per FTE					
Salaries	$ 183,367	$ 183,367	$ 192,827	$ 9,459	5.2%
Payroll Taxes	$ 10,969	$ 10,969	$ 11,162	$ 193	1.8%
Benefits	$ 38,405	$ 38,405	$ 40,054	$ 1,649	4.3%
Retirement	$ 22,985	$ 22,985	$ 22,392	$ (593)	-2.6%
Total Cost per FTE	**$ 255,726**	**$ 255,726**	**$ 266,434**	**$ 10,708**	**4.2%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Temporary office services were increased to provide assistance in administrative services.
- Education reimbursement cost is based on additional employee that has expressed interest in pursuing an advanced degree.
- Savings administration decrease is due to the termination of the defined benefit plan.

Table B-5 Meeting Expense

Meeting Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Meetings	$ 377,100	$ 377,100	$ 353,050	$ (24,050)	-6.4%
Travel	$ 855,232	$ 855,232	$ 834,500	$ (20,732)	-2.4%
Conference Calls	$ 37,000	$ 37,000	$ 37,000	$ -	0.0%
Total Meeting Expenses	**$ 1,269,332**	**$ 1,269,332**	**$ 1,224,550**	**$ (44,782)**	**-3.5%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Continued efforts to limit the number of attendees to offsite meetings and hold more meetings on-site and via webinar.

Table B-6 Consultants and Contracts

Consultants	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Consultants					
Reliability Standards	$ -	$ -	$ -	$ -	-
Compliance Enforcement and Organization Registration and Certification	$ -	$ -	$ -	$ -	-
Reliability Assessment and Performance Analysis	$ 35,000	$ 35,000	$ -	$ (35,000)	-100.0%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ -	$ -	$ -	$ -	-
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 30,000	$ 30,000	$ -	$ (30,000)	-100.0%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ -	$ -	$ -	$ -	-
Consultants Total	**$ 65,000**	**$ 65,000**	**$ -**	**$ (65,000)**	**-100.0%**

Contracts	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Reliability Standards	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Compliance Enforcement and Organization Registration and Certification	$ 1,274,000	$ 1,274,000	$ 1,254,000	$ (20,000)	-1.6%
Reliability Assessment and Performance Analysis	$ 378,000	$ 378,000	$ 401,640	$ 23,640	6.3%
Training and Education	$ -	$ -	$ -	$ -	-
Situation Awareness and Infrastructure Security	$ 160,000	$ 160,000	$ 120,000	$ (40,000)	-25.0%
Member Forums	$ -	$ -	$ -	$ -	-
General and Administrative	$ 115,000	$ 115,000	$ 85,000	$ (30,000)	-26.1%
Legal and Regulatory	$ -	$ -	$ -	$ -	-
Information Technology	$ -	$ -	$ -	$ -	-
Human Resources	$ -	$ -	$ -	$ -	-
Accounting and Finance	$ 7,000	$ 7,000	$ 7,000	$ -	0.0%
Contracts Total	**$ 1,944,000**	**$ 1,944,000**	**$ 1,877,640**	**$ (66,360)**	**-3.4%**
Total Consultants and Contracts	**$ 2,009,000**	**$ 2,009,000**	**$ 1,877,640**	**$ (131,360)**	**-6.5%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Ongoing effort to decrease the use of consultants and contractors when possible. (See program area sections for detail regarding a specific program area.)

Table B-7 Office Rent

Office Rent	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Office Rent	$ 650,000	$ 650,000	$ 650,000	$ -	0.0%
Utilities	$ 43,000	$ 43,000	$ 43,000	$ -	0.0%
Maintenance	$ 40,000	$ 40,000	$ 35,000	$ (5,000)	-12.5%
Security	$ 2,700	$ 2,700	$ 2,700	$ -	0.0%
Real Estate Taxes	$ 74,000	$ 74,000	$ 80,000	$ 6,000	8.1%
Total Office Rent	**$ 809,700**	**$ 809,700**	**$ 810,700**	**$ 1,000**	**0.1%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Projected increase in real estate taxes.

Table B-8 Office Costs

Office Costs	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Telephone	$ 112,000	$ 112,000	$ 111,660	$ (340)	-0.3%
Internet Expense	$ 105,600	$ 105,600	$ 95,000	$ (10,600)	-10.0%
Office Supplies	$ 33,000	$ 33,000	$ 33,000	$ -	0.0%
Computer Supplies and Maintenance	$ 350,000	$ 350,000	$ 350,600	$ 600	0.2%
Subscriptions & Publications	$ 13,500	$ 13,500	$ 13,500	$ -	0.0%
Dues	$ 4,400	$ 4,400	$ 3,400	$ (1,000)	-22.7%
Postage	$ 1,200	$ 1,200	$ 1,200	$ -	0.0%
Express Shipping	$ 10,000	$ 10,000	$ 10,000	$ -	0.0%
Copying	$ 26,400	$ 26,400	$ 26,400	$ -	0.0%
Reports	$ 6,000	$ 6,000	$ 8,000	$ 2,000	33.3%
Stationary and Office Forms	$ 2,000	$ 2,000	$ 2,000	$ -	0.0%
Equipment Repair/Service Contracts	$ -	$ -	$ -	$ -	-
Bank Charges	$ 15,000	$ 15,000	$ 10,000	$ (5,000)	-33.3%
Sales and Use Tax	$ -	$ -	$ -	$ -	-
Merchant Credit Card Fees	$ -	$ -	$ -	$ -	-
Presentation and Publicity	$ -	$ -	$ -	$ -	-
Total Office Costs	**$ 679,100**	**$ 679,100**	**$ 664,760**	**$ (14,340)**	**-2.1%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

Total Office costs are expected to remain relatively flat.

Table B-9 Professional Services

Professional Services	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
BOT Fee	$ 325,000	$ 325,000	$ 340,000	$ 15,000	4.6%
BOT Search Fee	$ 20,000	$ 20,000	$ -	$ (20,000)	-100.0%
Legal - Reorganization	$ -	$ -	$ -	$ -	-
Accounting & Auditing Fees	$ 310,000	$ 310,000	$ 300,000	$ (10,000)	-3.2%
Legal Fees - Other	$ 316,000	$ 316,000	$ 250,000	$ (66,000)	-20.9%
Insurance - Commercial	$ 70,000	$ 70,000	$ 70,000	$ -	0.0%
Total Services	**$ 1,041,000**	**$ 1,041,000**	**$ 960,000**	**$ (81,000)**	**-7.8%**

Explanation of Significant Variances –2018 Budget versus 2017 Budget

- Legal fees are projected to be lower based on additional workload taken on by in-house legal team.

Table B-10 – Miscellaneous

Miscellaneous Expense	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Miscellaneous Expense	$ 50,000	$ 50,000	$ 50,000	$ -	0.0%
Total Miscellaneous Expense	**$ 50,000**	**$ 50,000**	**$ 50,000**	**$ -**	**0.0%**

Table B-11 Other Non-Operating Expenses

Other Non-Operating Expenses	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Interest Expense	$ -	$ -	$ -	$ -	-
Office Relocation	$ -	$ -	$ -	$ -	-
Total Non-Operating Expenses	**$ -**	**$ -**	**$ -**	**$ -**	**-**

Table B-12 Fixed Assets

Fixed Assets	Budget 2017	Projection 2017	Budget 2018	Variance 2018 Budget v 2017 Budget	Variance %
Depreciation	$ (250,000)	$ (250,000)	$ (269,000)	$ (19,000)	7.6%
Equipment CapEx	$ -	$ -	$ -	$ -	-
Computer & Software CapEx	$ 276,000	$ 276,000	$ 115,000	$ (161,000)	-58.3%
Furniture & Fixtures CapEx	$ -	$ -	$ -	$ -	-
Leasehold Improvements	$ -	$ -	$ -	$ -	-
Allocation of Fixed Assets	$ -	$ -	$ -	$ -	-
Total Increase (Decrease) in Fixed Assets	**$ 26,000**	**$ 26,000**	**$ (154,000)**	**$ (180,000)**	**-692.3%**

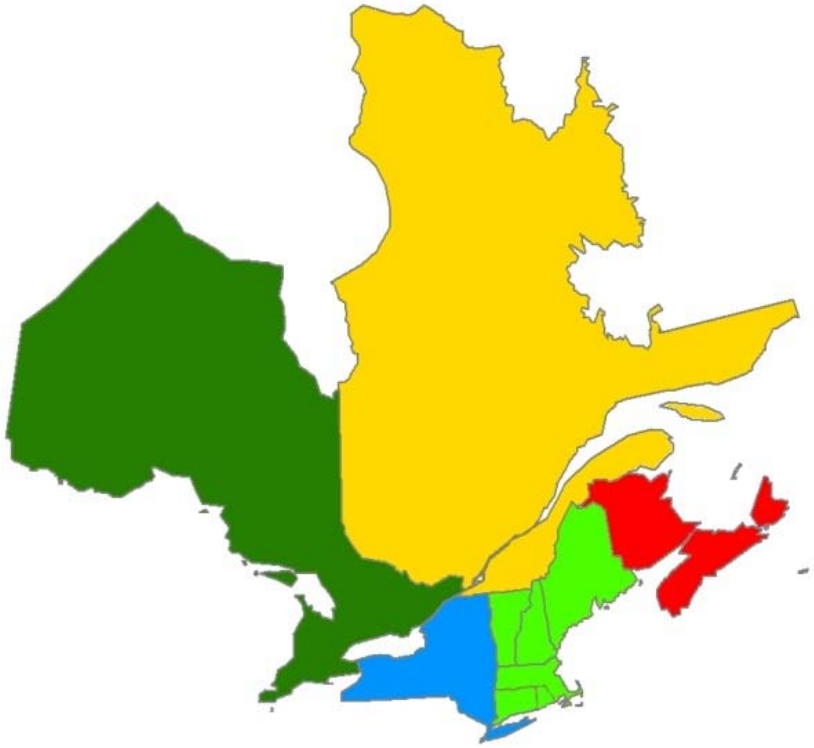
Table B-13 2018 and 2019 Projections

	Table to be Inserted	

Assumptions

Section C – Criteria Services Division Activities

2018 Business Plan and Budget



Section C —2018 Criteria Services Division Business Plan and Budget

Criteria Services Division (in w hole dollars)	2017 Budget	2018 Budget	Increase (Decrease)
Total FTEs	2.14	2.14	0.00
Total Direct Expenses	$623,747	$666,530	$42,783
Total Indirect Expenses	$413,149	$416,453	$3,304
Other Non-Operating Expenses	$0	$0	$0
Working Capital and Operating Reserves Requirement	$78,971	($47,843)	($126,813)
Inc(Dec) in Fixed Assets	($10,000)	($16,000)	($6,000)
Funding Requirement	$1,105,867	$1,019,141	($86,726)

NPCC Regionally-Specific Criteria Services Background

NPCC Criteria Services division activities are based on the development, maintenance (including retirement when no longer needed), and promulgation of Regionally-specific more stringent criteria, as well as criteria establishing resource adequacy requirements within the Region. These criteria contain requirements which are more stringent, more specific or augment the existing NERC Reliability Standards requirements. These criteria require continual evaluation to ensure they are "not inconsistent with" any NERC reliability standards as the standards are approved by FERC and the applicable provincial governmental authorities, as per the NERC Rules of Procedure.

Membership and Governance

Full members are subject to compliance with Regionally-specific criteria, in addition to continent-wide Reliability Standards, and receive criteria-related services from the Criteria Services division.

Full Members, aside from those who perform the Balancing Authority function, are not assessed an annual membership fee. Those that perform Balancing Authority functions are assessed and remit a proportional net energy for load share of expenses for criteria services. NPCC would also directly assign criteria service division costs to a Balancing Authority Area or entity, where significant costs are incurred for that Balancing Authority Area. The funding for NPCC's Criteria Services division is approved by the NPCC Board of Directors.

Criteria Services Division Functional Scope

Through its Criteria Services division, NPCC promotes the reliable and efficient operation of the international, interconnected bulk power systems in Northeastern North America through the establishment of Regionally-specific criteria, and monitoring and enforcement of compliance with such criteria.

NPCC provides Full Members with Regional reliability assurance services, and acts as the vehicle through which States and Provinces can fulfill their political mandates, with respect to resource adequacy, as well as overseeing the Northeastern North American electric infrastructure.

Major 2018 Assumptions and Cost Impacts

The Criteria Services division services are expected to remain stable throughout 2018

- The Criteria Compliance Enforcement Program (CCEP) review and evaluation process is the mechanism for monitoring key criteria attributes as determined by the respective NPCC Task Forces and the Compliance Committee.
- Past non-compliances, if any, followed the due process stated in the CCEP-1 process document and proper resolution/enforcement action taken.

2018 Primary Goals and Objectives

- Continue with the development and maintenance of a set of NPCC Directories which are "not inconsistent with" the NERC Reliability Standards and which clearly delineate the more stringent NPCC criteria requirements
    - The combination of North American and more-stringent NPCC Regional criteria provide for consistency and operational clarity while providing more robust defense in–depth, results based, criteria requirements to ensure BPS reliability
    - Continually review the criteria found in the NPCC Directories and the ERO standards to ensure no redundancies or inconsistencies exist.
    - Retire Directories and/or Criteria which have been overtaken by improved NERC standards
    - Continually file revised and updated more stringent requirements with the New York State Department of Public Service and Canadian Provinces as applicable
- Review, maintain, and revise the NPCC Regional Reliability Directories to facilitate compliance assessments and ensure the Criteria portions of the Directories are "not inconsistent" with, nor duplicative with, the approved and effective NERC Standards.
- The criteria services division and CCEP Working Group (reporting to the Compliance Committee) will work with the various Task Forces to develop Criteria Compliance Reporting Forms for any additional NPCC Directories to ensure that the more stringent or Regionally-specific criteria is being met.
- The criteria services division and CCEP working group will work with TFCO, TFCP, TFSS, and TFSP to review criteria and measures within each specific NPCC Directory to identify and develop them into specific reporting forms for approval.
- Continually review impact of Bulk Electric System definition on Directory and Criteria content and compliance reporting.
- Continually review potential impacts of Sector or NPCC organizational changes on the Directories and Criteria by performing a review of enforcement and arbitration processes as needed
- Assist Legal with preparation of revised Directories for Regulatory filings with the individual Provinces in accordance with their respective Memorandum of Understandings (MOUs) as well as the State of New York Public Service Commission
- Facilitate any requested clarifications for NPCC Criteria with the necessary subject matter experts and also identify any other potential opportunities for clarifications of the Criteria.
- Conduct review of the following Documents:

- Directory No. 7 – *Special Protection Systems* – the TFSP will serve as lead Task Force working in conjunction with TFCP and TFSS on revisions required to ensure consistency with the development of the NERC standard on Remedial Action Schemes.
- *A-10 - Classification of Bulk Power System Elements* - the TFCP will conclude its review of the A-10 methodology in 2018.
- Review and respond to Requests for Clarifications to existing NPCC Standards, Directories, and Criteria.

NPCC Reliability Directory Maintenance and Development

The NPCC Regional Reliability Directories were developed to demonstrate that the NPCC more stringent criteria are "not inconsistent with" the NERC Reliability Standards as mandated by the NERC Rules of Procedure. The conversion of NPCC's criteria into Directories was undertaken to remove any redundancies with the NERC or NPCC Regional Reliability Standards and to clearly delineate the more stringent NPCC criteria requirements, assign Functional Model designations to those responsible for compliance and create measurable compliance criteria. Subsequent to the initial establishment of the Directories, which also organized functionally related B Guidelines and C Procedures into a single Directory, the Directories were further reviewed to translate existing criteria language into a "requirement type" format. The development of the criteria into NERC style requirements facilitates the NPCC Region's CCEP and also ensures the delineation of the more stringent and more specific Regional criteria from the latest approved and effective set of NERC ERO standards.

In 2018, work will continue with the maintenance, revision, or potential retirement of individual Directories to address any actual or anticipated redundancies with new or modified NERC or NPCC Reliability Standards. The ongoing review and maintenance of the Directories will require Task Force and Criteria Services staff to support this effort and to serve as subject matter experts. In addition to the ongoing review of the criteria within the Directories for potential duplicity with the NERC standards, any Directories that have not had the criteria translated into NERC style requirements will also be reviewed in order to achieve criteria 'requirements' which are clear, concise and measurable. Also, a standards style template will be applied to the existing Directories to make them more consistent with the look of the standards. As NERC standards improve, the need for NPCC Directories and the amount of criteria contained therein will decrease over time, however in the interim, significant review is necessary to ensure the criteria remain "not inconsistent with" the NERC standards as outlined in the NERC Rules of Procedure. NPCC will conduct internal reviews of all draft standards against Regional criteria and utilize subject matter experts to identify reliability and compliance related concerns. NPCC will file the revised NPCC Directories and notifications of retirements of Directories with the Canadian governmental and/or provincial Regulatory authorities within the NPCC "footprint", on an as needed basis, in accordance with established provincial procedures and agreements executed with NPCC.

NPCC Operations and Planning Directories

The following Directories are envisioned to remain active for 2018.

Directory #1, *Design and Operation of the Bulk Power System.*

This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing NERC TPL, BAL, IRO, INT, MOD, TOP, PRC and VAR standards. The NPCC TFCP and TFCO completed a review of the Directory#1 criteria in 2015, during which the criteria was translated into NERC style requirements and revisions were enacted to ensure consistency with recent changes to the TPL and TOP standards.

Directory #2, *Emergency Operations*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing NERC EOP and TOP standards. The NPCC Task Force on Coordination of Operation is reviewing this Directory in 2017.

Directory # 4, *System Protection Criteria*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain applicable NERC PRC standards. The NPCC Task Force on System Protection will lead this review and revision.

Directory # 5, *Reserve*
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with all the existing applicable NERC BAL, INT, and IRO standards. The NPCC Task Force on Coordination of Operation will lead this review and revision and ensure consistency with the BAL standards.

Directory # 7, *Special Protection Systems*
This Directory documents NPCC's Regionally-specific, more stringent criteria for application and approval of SPS. The NPCC Task Force on System Protection will lead this review and revision and ensure consistency with the Remedial Action Scheme PRC-012 standard.

Directory # 8, *System Restoration*
This Directory documents NPCC's Regionally-specific, more stringent criteria with which each applicable entity must plan for and perform power system restoration following a major or a total blackout, and demonstrates coordination and consistency with applicable NERC EOP standards. The NPCC Task Force on Coordination of Operation will lead this review and revision.

Directory # 11, *Disturbance Monitoring Equipment*,
This directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain existing NERC PRC standards. The NPCC Task Force on System Protection anticipates the development and approval of Directory#11 in order to facilitate the retirement of PRC -002-NPCC-1 and will lead this review and revision.

Directory # 12, *Automatic UFLS Program Requirements*,
This Directory documents NPCC's Regionally-specific, more stringent criteria, and demonstrates coordination and consistency with certain existing NERC and NPCC PRC standard(s). The NPCC Task Force on System Studies will lead this review and revision until such time as the NPCC PRC-006-01 UFLS Regional Standard is approved by the NPCC membership, NERC BOT, the FERC and all the applicable governmental authorities in the Provinces of Canada within NPCC's footprint.

NPCC Criteria Compliance Background

The NPCC criteria services division assures the reliable operation of the bulk power system through implementation of a comprehensive compliance program. This program which includes monitoring, assessing and enforcing compliance with the more stringent, Regionally specific NPCC Criteria requirements, is known as the NPCC Criteria Compliance and Enforcement Program (CCEP) described in process document CCEP-1. This program was developed by the criteria services division and the CCEP Working Group under the purview of the NPCC Compliance Committee. The results of this program support the various Task Forces in their assessments of the NPCC criteria in meeting their goals for the Reliability Coordinating Committee as stated in Section A of this Business Plan.

The more stringent, Regionally-specific NPCC Criteria requirements reflect the unique operational and planning aspects of the bulk power system within the NPCC Region and are included in the NPCC "A" documents and their successors, the NPCC Directories.

NPCC issues non-monetary sanctions to enforce compliance with NPCC Criteria.

- The CCEP program is described in document CCEP-1, *NPCC Criteria Compliance and Enforcement Program (CCEP) Process Document*
- The implementation plan is described in document CCEP-2, *Implementation Plan for 2011 NPCC Criteria Compliance and Enforcement Program*
- On April 5, 2011, the above became effective upon Full Member approval of CCEP-1, and CCEP-2 and retired the following
    - NPCC Criteria A-8, Reliability Compliance and Enforcement Program (RCEP)
    - NPCC Guide B-22, Guidelines for Implementation of the NPCC Inc. Compliance Program
    - NPCC Procedure C-32, Review Process for NPCC Reliability Compliance Enforcement Program
    - Each of the above have been annotated as "retired effective 4/5/11 upon Full Member approval of CCEP-1… and CCEP-2…" on the NPCC public website

- The CCEP-1 document recognizes the applicability of NPCC's Regionally-specific, more stringent reliability criteria to the Full Members of NPCC, consistent with the *Amended and Restated ByLaws*, and respects the provisions of the several Canadian Memoranda of Understanding in the execution of the processes described
- Provides a comprehensive CCEP Process Diagram showing the process of evaluating and approving Criteria Certification submittals, and additional processes and responsibilities in the event that non-compliances, disputes and sanctions arise
- Describes the roles and responsibilities of Reporting Members, the CC, the RCC and the Enforcement Panel in the compliance review and enforcement process
- Describes Levels of Non-Compliance, associated non-monetary Sanctions, Lateness Policy and the Arbitration/Dispute Resolution process
- Addresses Mitigation Plans for any violations under the enforcement process; and
- Lists the mandatory Certification Forms to be submitted for review by the Task Forces to ensure compliance with NPCC Directories are being met

The CCEP currently requires annual submittal of Certification Forms by the Reliability Coordinators and Balancing Authorities to confirm compliance with various NPCC Directories. Currently the required Certification forms are for Directory #1- *Area Transmission Review*, Directory #8 - *Key Facility List*, Directory #9 – *Generator Real Power Verification*, Directory #10 - *Verification of Generator Gross and Net Reactive Power Capability*, and Directory #12 - *UFLS Program Requirements*. In 2017 NPCC will consider an expansion of the CCEP to include compliance assessment activities to other active Directories.

The CCEP identifies those specific NPCC Directories that are subject to monitoring, assessment and enforcement.

The NPCC Compliance Committee (CC) has final approval of compliance assessments related to CCEP. The CCEP describes the roles and responsibilities of committees and panels used to resolve contested compliance and/or sanction or penalty determinations related to NPCC Directories.

Explanation of Significant Variances – 2018 Budget versus 2017 Budget

Resource Requirements

Personnel

- NPCC anticipates no need to hire additional personnel in this program area in 2018.

2017 Budget and Projection and 2018 Budget Comparisons

Statement of Activities and Capital Expenditures
2017 Budget & Projection, and 2018 Budget
CRITERIA SERVICES DIVISION

		2017 Budget	2017 Projection	Variance 2017 Projection v 2017 Budget Over(Under)	2018 Budget	Variance 2018 Budget v 2017 Budget Over(Under)
Funding						
ERO Funding						
	ERO Assessments	$ -	$ -	$ -	$ -	$ -
	Penalty Sanctions	-	-	-	-	-
Total ERO Funding		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Membership Dues	1,105,867	1,105,867	-	1,019,141	(86,726)
	Testing Fees	-	-	-	-	-
	Services & Software	-	-	-	-	-
	Workshops	-	-	-	-	-
	Interest	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Total Funding (A)		**$ 1,105,867**	**$ 1,105,867**	**$ -**	**$ 1,019,141**	**$ (86,726)**
Expenses						
Personnel Expenses						
	Salaries	$ 401,142	$ 401,142	$ -	$ 404,848	$ 3,706
	Payroll Taxes	23,301	23,301	-	23,413	112
	Benefits	69,100	69,100	-	74,991	5,892
	Retirement Costs	42,605	42,605	-	43,272	667
Total Personnel Expenses		**$ 536,147**	**$ 536,147**	**$ -**	**$ 546,523**	**$ 10,376**
Meeting Expenses						
	Meetings	$ 5,000	$ 5,000	$ -	$ 5,000	$ -
	Travel	51,600	51,600	-	55,647	4,047
	Conference Calls	-	-	-	-	-
Total Meeting Expenses		**$ 56,600**	**$ 56,600**	**$ -**	**$ 60,647**	**$ 4,047**
Operating Expenses						
	Consultants & Contracts	$ 18,000	$ 18,000	$ -	$ 40,360	$ 22,360
	Office Rent	-	-	-	-	-
	Office Costs	-	-	-	-	-
	Professional Services	-	-	-	-	-
	Computer & Equipment Leases	-	-	-	-	-
	Miscellaneous	3,000	3,000	-	3,000	-
	Depreciation	10,000	10,000	-	16,000	6,000
Total Operating Expenses		**$ 31,000**	**$ 31,000**	**$ -**	**$ 59,360**	**$ 28,360**
	Total Direct Expenses	**$ 623,747**	**$ 623,747**	**$ -**	**$ 666,530**	**$ 42,783**
Indirect Expenses		**$ 413,149**	**$ 413,149**	**$ -**	**$ 416,453**	**$ 3,304**
Other Non-Operating Expenses		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Expenses (B)		**$ 1,036,896**	**$ 1,036,896**	**$ -**	**$ 1,082,983**	**$ 46,087**
Change in Assets		**$ 68,971**	**$ 68,971**	**$ -**	**$ (63,843)**	**$ (132,813)**
Fixed Assets						
	Depreciation	$ (10,000)	(10,000)	$ -	$ (16,000)	$ (6,000)
	Computer & Software CapEx	-	-	-	-	-
	Furniture & Fixtures CapEx	-	-	-	-	-
	Equipment CapEx	-	-	-	-	-
	Leasehold Improvements	-	-	-	-	-
	Allocation of Fixed Assets	-	-	-	-	-
Inc(Dec) in Fixed Assets (C)		**(10,000)**	**(10,000)**	**-**	**(16,000)**	**(6,000)**
TOTAL BUDGET (=B+C)		1,026,896	1,026,896	-	1,066,983	40,087
TOTAL CHANGE IN WORKING CAPITAL (=A-B-C)		**$ 78,971**	**$ 78,971**	**$ -**	**$ (47,843)**	**$ (126,813)**

Personnel Analysis

Total FTE's by Program Area	Budget 2017	Projection 2017	Direct FTEs 2018 Budget	Shared FTEs1 2018 Budget	Total FTEs 2018 Budget	Change from 2017 Budget
CRITERIA SERVICES DIVISION						
Operational Programs						
Reliability Standards	1.07	1.07	1.00	0.07	1.07	0.00
Compliance Enforcement and Organization Registration and Certification	0.00	0.00	0.00	0.00	0.00	0.00
Training and Education	0.00	0.00	0.00	0.00	0.00	0.00
Reliability Assessment and Performance Analysis	1.07	1.07	1.00	0.07	1.07	0.00
Situation Awareness and Infrastructure Security	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Operational Programs	**2.14**	**2.14**	**2.00**	**0.14**	**2.14**	**0.00**
Administrative Programs						
Member Forums	0.00	0.00	0.00	0.00	0.00	0.00
General and Administrative	0.00	0.00	0.00	0.00	0.00	0.00
Information Technology	0.00	0.00	0.00	0.00	0.00	0.00
Legal and Regulatory	0.00	0.00	0.00	0.00	0.00	0.00
Human Resources	0.00	0.00	0.00	0.00	0.00	0.00
Accounting and Finance	0.00	0.00	0.00	0.00	0.00	0.00
Total FTEs Administrative Programs	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**
Total FTEs	**2.14**	**2.14**	**2.00**	**0.14**	**2.14**	**0.00**

[1]A shared FTE is defined as an employee who performs both Regional Entity and Criteria Services division functions.

Reserve Analysis 2017 - 2018

Working Capital and Operating Reserve Analysis 2017-2018
CRITERIA SERVICES DIVISION

	Total Reserve	Operating Reserve	Working Capital	Business Continuity
Beginning Total Reserve, December 31, 2016	384,529	295,774	88,755	
2017 Non-Statutory Funding (from members)	1,105,867	1,105,867	0	
2017 Other funding sources	0	0	0	
Less: 2017 Projected expenses & fixed asset additions	(1,026,896)	(1,026,896)	0	
Projected Working Capital and Operating Reserve, December 31, 2017	**463,500**	**374,745**	**88,755**	
Desired Working Capital and Operating Reserve, December 31, 2018 [1]	**355,657**	266,746 [2]	88,912 [3]	
Desired Business Continuity Reserve, December 31, 2018	**60,000**			60,000
Less: Projected Working Capital and Operating Reserve, December 31, 2017	(463,500)	(374,745)	(88,755)	
Increase(decrease) in assessments to achieve desired Total Reserve	(47,843)	(107,999)	157	

2018 Funding requirement for expenses and fixed asset additions	1,066,983
Adjustment to achieve desired Working Capital and Operating Reserve balance	(47,843)
2017 Funding and reserve requirement	1,019,141

[1] Total Reserve within a range of 16.67% - 33.33% of Budget.

[2] Total NPCC Operating Reserve must be within a range from 8.33% to 25.00% of Budget. $266,746 represents 25.00% of the 2017 CS budget of $1,066,983.

[3] Total NPCC Working Capital must equal 8.33% of Budget. $88,912 represents 8.33% of the 2017 CS budget of $1,066,983.

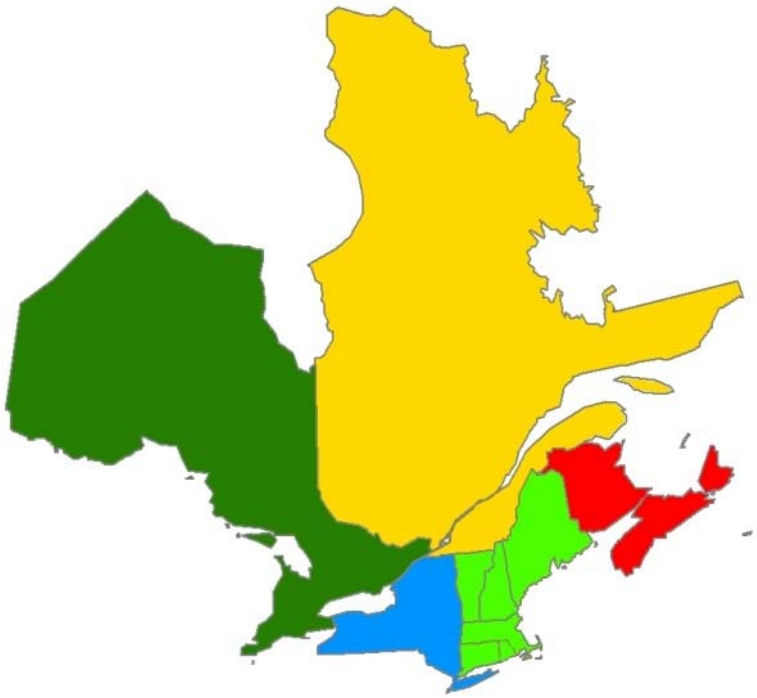
[4] Establish Business Continuity Reserve as approved by the NPCC Board of Directors upon recommendation by the MDCC.

Explanation of Changes in Reserve Policy from Prior Year

There was no change to the existing Working Capital and Operating Reserve Policy, however, a separate Business Continuity Reserve (BCR) in the amount of $1,000,000 (allocated between the Regional Entity and Criteria Services divisions) was established as approved by the NPCC Board of Directors, upon recommendation by the Management Development and Compensation Committee and endorsement by the Finance and Audit Committee, to be identified as restricted cash and drawn upon as subsequently brought before the Board of Directors in association with President & CEO succession related activities associated with a planned or sudden retirement, as well as other sudden changing workforce staffing requirements.

Section D – Additional Consolidated Financial Statements

2018 Business Plan and Budget



Section D — Additional Financial Statements

Statement of Financial Position

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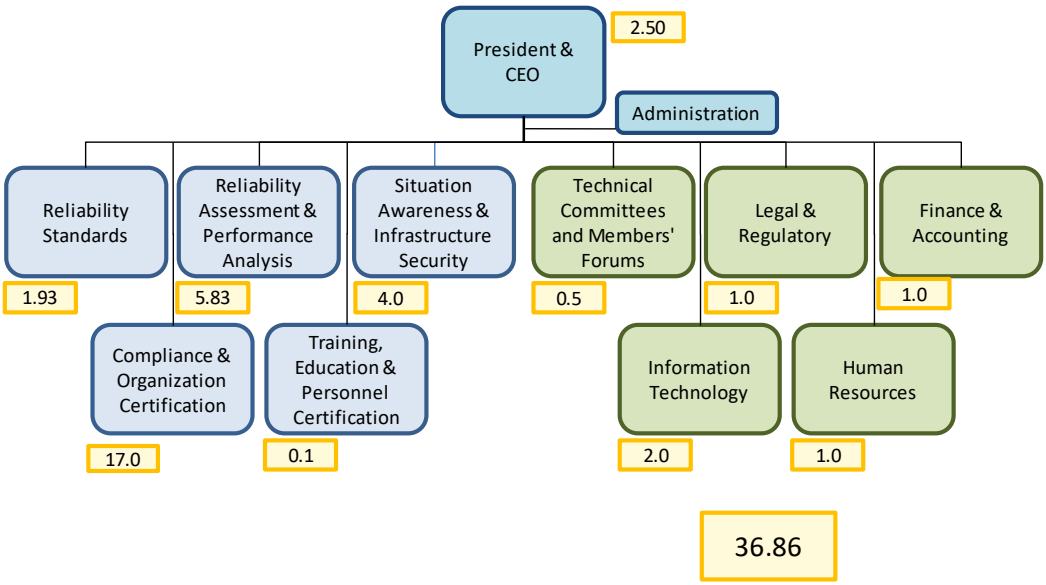
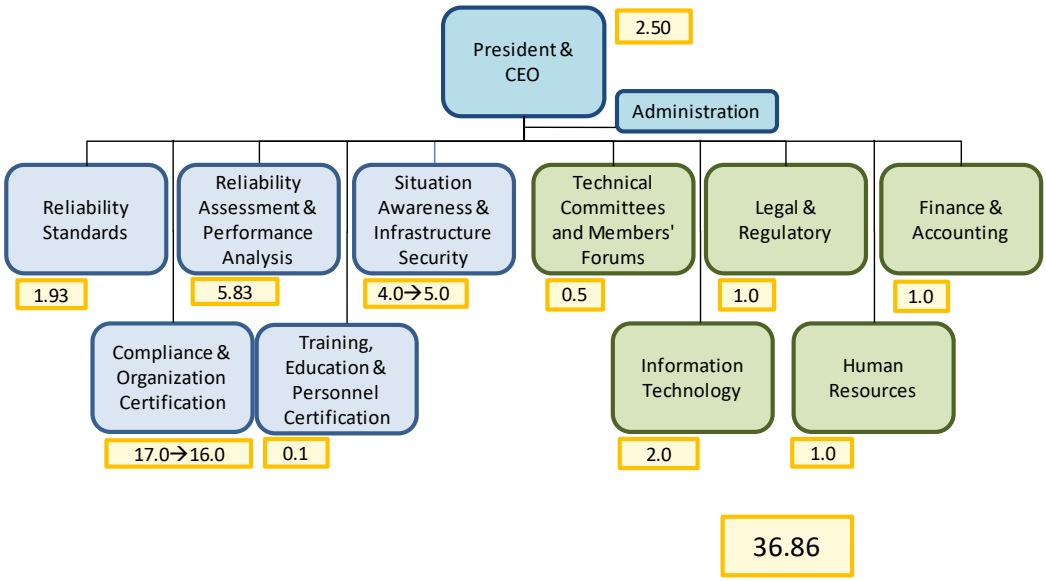
Appendix A Staff Allocations

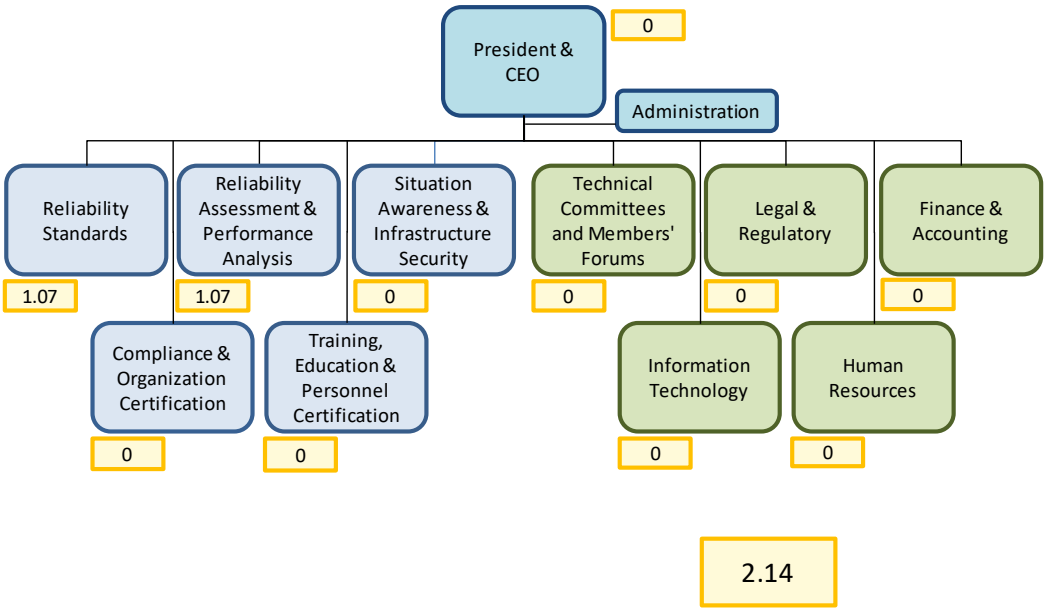
2017 Budget Staff Allocations - RE Division



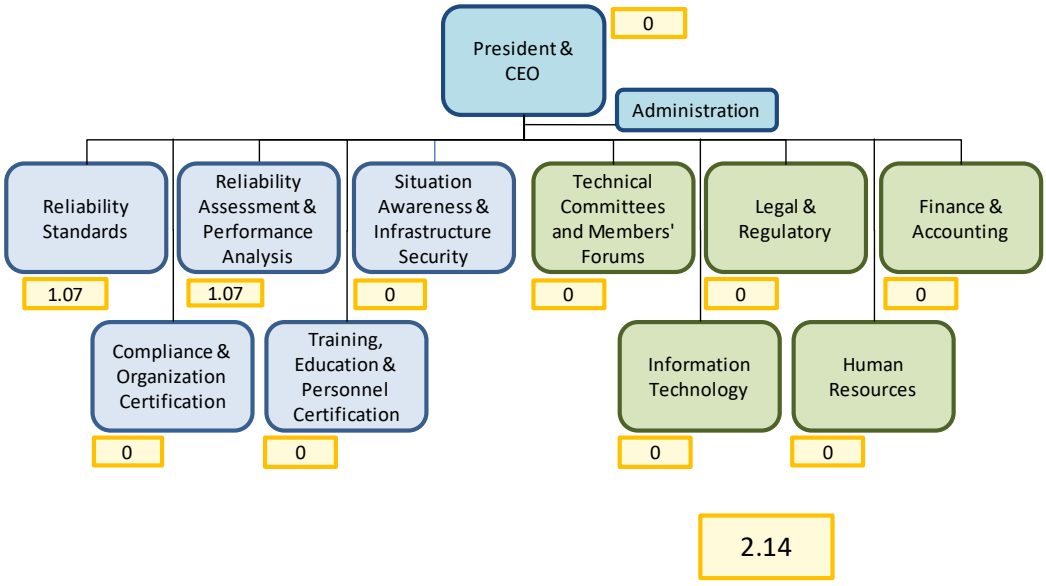
2018 Budget Staff Allocations - RE Division



2017 Budget Staff Allocations - CS Division



2018 Budget Staff Allocations - CS Division



Appendix B Acronyms

This section lists acronyms used in this document.

Acronym	Definition
AI	Audits and Investigations
BAA	Balancing Authority Area
BEPWG	BES Exception Process Working Group
BES	Bulk Electric System
BOT	Board of Trustees
BPS	Bulk Power System
CC	Compliance Committee
CCEP	Criteria Compliance Enforcement Program
CDAA	CMEP Data Administration Application
CEAP	Cost Effective Analysis Process
CEH	Continuing Education Hour
CGNC	Corporate Governance and Nominating Committee
CIPC	Critical Infrastructure Protection Committee
CIPIS	Critical Information Protection Information Sharing
CMEP	Compliance Monitoring and Enforcement Program
CORC	Compliance Monitoring and Enforcement and Organization Registration and Certification Program
CPP	Clean Power Plan
CRRA	Cost of Risk Reduction Analysis
CUG	Consortium Users Group
DADS	Demand Availability Data System
DADSWG	Demand Response Availability Data System Working Group
ERA	Entity Reliability Assessment
ERAG	Eastern Interconnection Reliability Assessment Group
ERO	Electric Reliability Organization
EUB	Electric Utility Board
EUB	Energy and Utilities Board
FAC	Finance and Audit Committee
FERC	Federal Energy Regulatory Commission
FFT	Find, Fix, Track
GADS	Generator Availability Data System
GADSWG	Generating Availability Data System Working Group
GMD	Geomagnetic Disturbance
HQCMÉ	Hydro-Québec Contrôle des mouvements d'énergie
HSIN	Homeland Security Information Network
ICE	Internal Controls Evaluation
IED	Intelligent Electronic Device
IERP	Independent Experts Review Panel Report
IESO	Independent Electricity System Operator
IRA	Inherent Risk Assessment
ISO	Independent System Operator
ITSG	IT Steering Group
LCEFT	Load, Capacity, Energy, Fuels, and Transmission
LMS	Learning Management System
LMWG	Load Modeling Working Group
LSE	Load Serving Entity
MACD	Market Assessment and Compliance Division of the IESO
MDCC	Management Development and Compensation Committee
ME	Mitigation and Enforcement
MMWG	Multi-Regional Modeling Working Group
MOU	Memorandum of Understanding
MPLS	Multiprotocol Label Switching
MVWG	Model Validation Working Group
NAESB	North American Electric Standards Review Board

Acronym	Definition
NEL	Net Energy for Load
NERC	North American Electric Reliability Corporation
NOAV	Notice of Alleged Violation
NOCV	Notice of Confirmed Violation
NOPR	Notice of Proposed Rulemaking
NOPV	Notice of Possible Violation
NPCC	Northeast Power Coordinating Council, Inc.
NRAP	NPCC Reliability Assessment program
NSPI	Nova Scotia Power Incorporated
NSUARB	Nova Scotia Utility and Review Board
OEB	Ontario Energy Board
PAS	Performance Analysis Subcommittee
PC	Pension Committee
PMOS	Project Management Oversight Subcommittee
PSMTF	Protection System Mis-operations Task Force
PSTN	Public Switched Telephone Network
QCMEP	Québec Reliability Standards Compliance Monitoring and Enforcement Program
RADS	Reliability Assessment Data System
RADWG	Reliability Assessment Data Working Group
RAS	Reliability Assessment Subcommittee
RC	Reliability Coordinator
RCC	Reliability Coordinating Committee
RISC	Reliability Issues Steering Committee
RSAW	Reliability Standards Audit Worksheet
RSC	Regional Standards Committee
RTO	Regional Transmission Organization
SAFNR	Situational Awareness-FERC, NERC, Regions
SAMS	System Analysis and Modeling Subcommittee
SAR	Standards Authorization Request
SAT	Systematic Approach to Training
SBS	Standards Balloting System
SCPS	Standards Committee Process Subcommittee
SDT	Standards Drafting Team
SEDS	Spare Equipment Database System
SEDTF	Spare Equipment Database Task Force
SPS	Special Protection Systems
TADS	Transmission Availability Data System
TADSWG	Transmission Availability Data System Working Group
TFCO	Task Force on Coordination of Operation
TFCP	Task Force on Coordination of Planning
TFE	Technical Feasibility Exception
TFIST	Task Force on Infrastructure Security and Technology
TFSP	Task Force on System Protection
TFSS	Task Force on System Studies
TLR	Transmission Loading Relief
TOP	Transmission Operator
UFLS	Underfrequency Load Shedding
UVLS	Under-Voltage Load Shedding
VRF	Violation Risk Factor
VSL	Violation Security Level

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